Potential Load Impacts of Residential Time of Use Rates in California

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Executive Summary

The California Energy Commission (CEC), the California Independent System Operator (CAISO), and the California Public Utilities Commission (CPUC) staff, together as the Joint Agency Steering Committee (JASC), are collaborating on a supplemental analysis to the 2015 Integrated Energy Policy Report (IEPR) baseline forecast that examines the potential load impacts of changes to time-varying rates and other rate design elements. In support of this effort, MRW & Associates, LLC (MRW) was retained by the CEC to examine the available literature on the impact of residential time-of-use (TOU) rate designs on load and to use the demand elasticities observed in the literature to model the impact of a several TOU rate design scenarios on residential demand and energy usage.

The impetus for the study is twofold. First, as with many jurisdictions, the JASC was interested in better understanding the potential summer peak-demand reduction that could be induced by higher on-peak residential rates. Second, the JASC, and CAISO in particular, were interested in to what degree TOU rates could be used to address the belly of the so-called "duck curve." [1] That is, on spring afternoons when solar output is high and usage is modest, could providing residential electricity users a price signal (low rates) to consume more during these hours help stave off potential over-generation events and renewable curtailment?

Literature Review

The literature search focused pilot programs and studies that met the following criteria:

1. Were published in the last ten years (i.e., since 2006);
2. Were relevant to California climates; and
3. Provided quantitative results.

Exceptions to these criteria were made for particularly relevant studies, such as the Charles River Associates *Impact Evaluation of the California Statewide Pricing Pilot*, which was published in 2005. Because even these relatively broad categories significantly narrowed the pool of applicable studies, MRW also included studies from overseas as well as pilots that looked at critical peak pricing (CPP). Over 48 studies were identified as potentially useful, and the most relevant 33 were summarized.

The literature review found that differing variables made direct comparisons difficult. These variables includes participant opt-in versus default participation, with or without enabling technologies, widely varying TOU rates and peak-period definitions, to name a few. Estimates of own-price elasticity ranged by over an order of magnitude, from -0.65 to 0.26 observed in the Salt River Project (SRP), to -0.003 observed in the California Statewide Pricing Pilot (SPP). Estimations of substitution elasticity varied from -0.081 as observed in the SPP, to -0.131 observed by SMUD.

[1] E.g., CAISO, "Demand Response and Energy Efficiency Roadmap: Maximizing Preferred Resources," December, 2013.

Given the purpose of the study, MRW identified two shortfalls in the data from the literature review. First, none of the studies examined the impacts of three TOU periods (i.e., off-peak, partial-peak, and peak). This is a problem because the proposed updated TOU rates for SDG&E and SCE both contemplate three-part TOU designs. Second, very few examined the non-summer impacts, and those that did were not designed to address the overgenertion issue (i.e., loads falling below the output of the must-take generators on the CAISO grid). Because of its direct applicability to California and its inclusion of elasticity estimates for non-summer periods, MRW replied upon the California State-Wide Pricing Pilot for the elasticities used in the modeling.

TOU Rate Impact Modeling

MRW model six TOU rate scenarios defined by the JASC for each of the three major California investor-owned utilities. The six scenarios, summarized in the table detail below, vary by TOU period, customer participation (% opt-in), and rates. The first scenario uses the current TOU rates and modest participation rates. Scenarios 2, 3, and 4 used the TOU rates that have been proposed by the IOUs, with increasing participation rates. Scenarios 5 and 6 used TOU periods that aligned with the CAISO's system loads and relatively extreme rate differentials (from 7.5¢/kWh to 60¢/kWh). Scenarios 5 and 6 differ only in the assumed customer opt-in rate.

Table ES-1: JASC Rate Scenarios

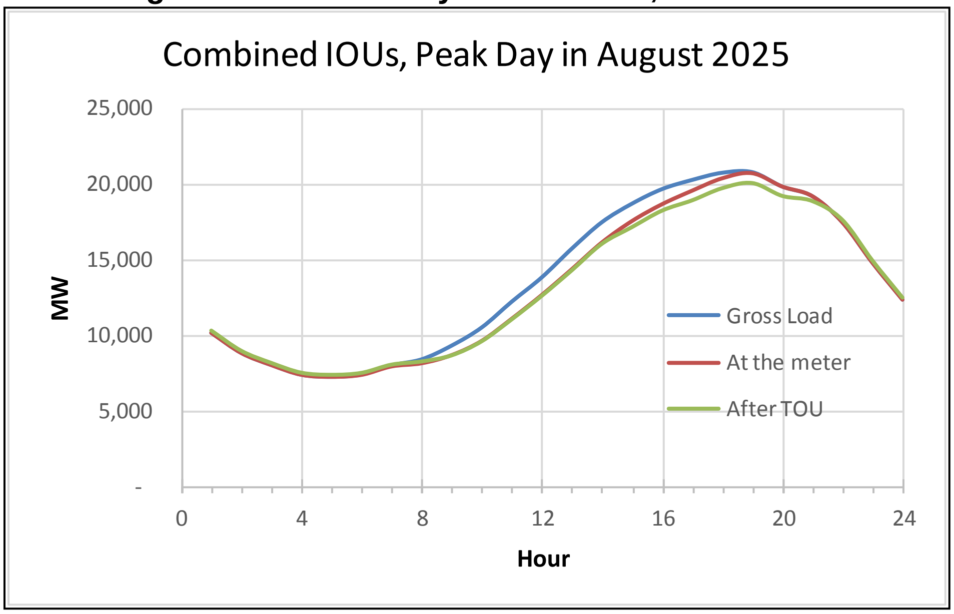
Scenario	Description	Customer Opt-In Rate	TOU Peak Periods		
			PG&E	SCE	SDG&E
Scenario 1	Current TOU, Low Participation	10% by 2025	12 pm – 6 pm (current)	12 pm – 6 pm (current) 2 pm – 8 pm (optional rate)	11 am – 6 pm (current)
Scenario 2	IOU Proposed, Low Participation	10% by 2025	4 pm – 9 pm (proposed)	2 pm – 8 pm (effective 2019)	2 pm – 9 pm (proposed)
Scenario 3	IOU Proposed, High Participation	30% by 2025			
Scenario 4	IOU Proposed, Default TOU	80% by 2025			
Scenario 5	CAISO Proposed, Default TOU	80% by 2025	12 pm – 4 pm (July and August) 4 pm – 9 pm (all other months)		
Scenario 6	CAISO Proposed, High Participation	30% by 2025			

In addition to these Base Cases, MRW also modeled an "Expected+ Case," which uses the same daily price elasticity inputs but with substitution elasticities modified to simulate the use of enabling technologies (i.e., devices that assist users shift their usage).

Base Case the modeling suggests that the current and proposed time of use rates (Scenarios 1 through 4) can induce modest peak reductions, on the order of 100 MW to 800 MW statewide for the three major investor owned utilities. Key factors that contribute to the range are assumed participation rates, and to a lesser degree the penetration of enabling technologies.

Figure 2 below, shows the CAISO-wide peak day for residential demand (August 13 using the data analyzed here). Three lines are shown. The top blue line shows the gross usage of the residential class under flat rates, prior to any solar PV is taken into account. This is load to which the CES elasticity formulae are applied. The second, red line shows the load at the meter, after accounting for behind the meter solar PV. The third generally bottom line is the load at the meter after the TOU rates have been applied. The figure is from Scenario 4 (80% participation with IOU proposed TOU periods) so as to make the impacts more visible.

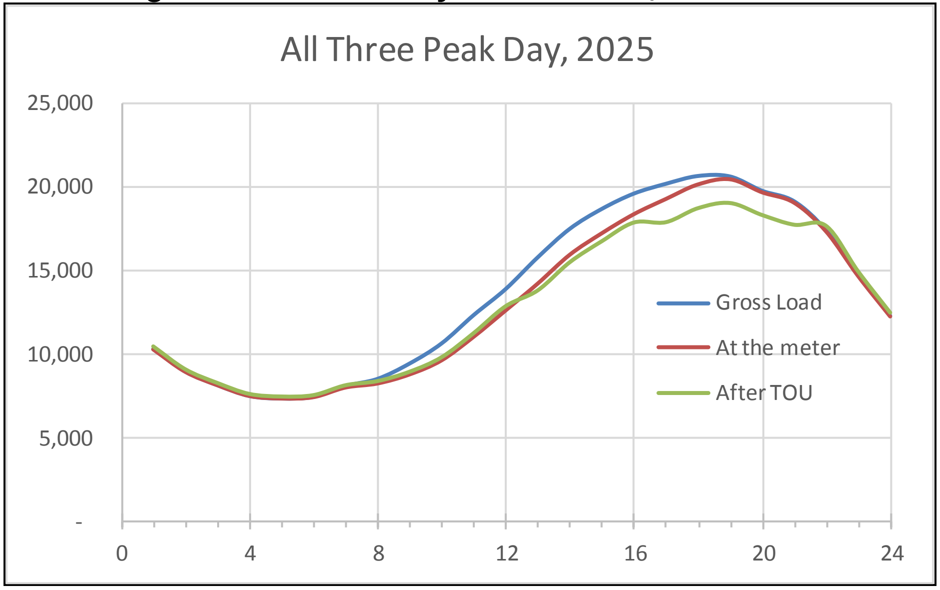
Figure ES-1. Peak Day Load Profile, Scenario 4.



As seen in the figure, at its maximum at 7:00 pm, the Scenario 4 TOU rate (utility proposed rate designs and high penetrations) would decrease the peak demand by approximately 630 MW. While not insignificant, it is still relatively small on a percentage basis. When moderate levels of enabling technologies are included in the Enhanced+ Case, the peak-hour reduction increases to about 800 MW.

The Figure also shows the residential peak day profile for Scenario 5, which is the most aggressive scenario, using the CAISO-defined TOU periods and a default participation. Two major differences can be seen between this figure and the analogous one for Scenario 4. First, the magnitude of the load decrease during the peak hours is more pronounced. At the 7:00 pm peak, the TOU rates would decrease the peak demand by 1,400 MW, 125% greater than the impact with the same participation rate (80%) but with the more standard TOU rate design. Second, discernible part-peak decreases can also be seen, as the green line (with TOU rates) is now distinctly below the red line (at the meter load without TOU rates).

Figure ES-2. Peak Day Load Profile,Scenario 5



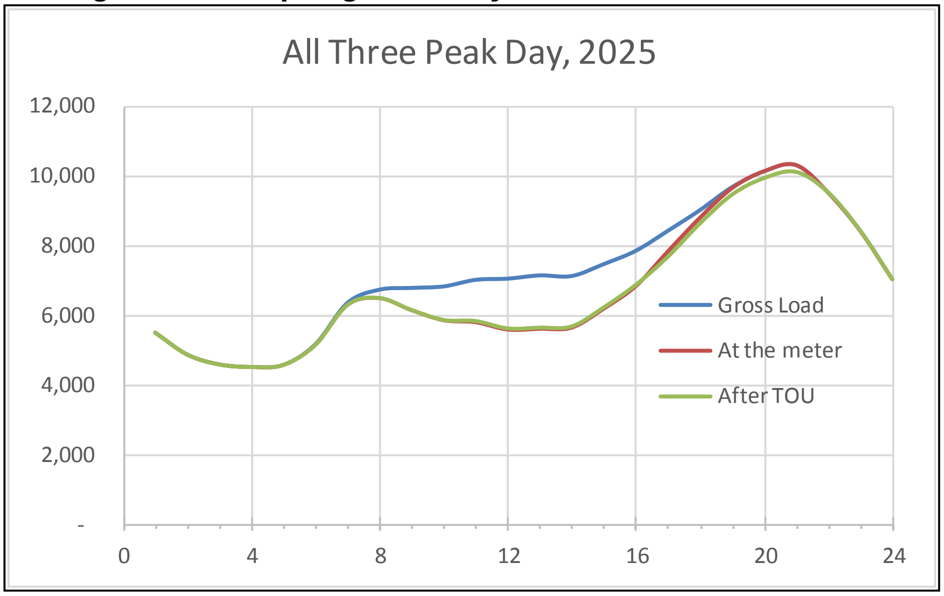
As noted, the impact of the TOU rates on the spring daylight hours was also of interest. As should be expected, because the rates were not designed to address to induce additional consumption in these hours, the scenarios based on current and proposed TOU periods (scenarios 1-4) showed only very nominal to counterproductive impacts. Overall, the model suggests that the induced load increases in the spring would be only on the order of a few tens of megawatts. Furthermore, SCE's proposed design maintains the "reduced the load during the day" price signals and thus would actually decrease loads during spring afternoons.

The figure below shows the spring weekday load profile for Scenario 5, which is designed specifically to incent additional usage in the spring afternoons. While discernible on the graph, the predicted impact of the TOU rate is still modest: only about 60 MW. This is attributable primarily to the small substitution elasticity of demand (-0.012). For experimentation purposes, when an aggressive substitution elasticity (-0.066) is applied, the projected impact more than triples to over 200 MW.[2]

Greater impacts are observed when the more aggressive TOU rate design is applied on the spring weekends. Unlike the standard TOU rate design, the time periods remain targeted, with super-off peak rates in the mid-afternoon, with a large differential between them and the adjacent part-peak rates (ratio of 1: 2.9). In this case, greater impacts are predicted. With the base case elasticity, the load increase in the afternoon hours is projected to be around 150 MW, while with the very aggressive substitution elasticity the load increase modeled to be over 300 MW.

[2] This value is based on some of the results from a pilot conducted by a Pennsylvania utility. Because of climate and demographic differences, this value is for illustration only and without more specific California-based pilots, cannot be assumed to be applicable here.

Figure ES-3. Spring Weekday Load Profile, Scenario 5



Conclusions

The load impacts of residential time of use rates have been extensively investigated; there are scores of academic and conference papers analyzing nearly as many pilots. Even so, various differing variables often make direct comparisons difficult. Some are voluntary, others are opt-out; some are just for limited critical peak hours, others have set hours (which then vary between pilots). All but ones in Ontario, Canada, Pennsylvania and California did not consider impacts outside of the summer peak hours. None considered three TOU periods.

Because no existing pilot or study is directly applicable to the analysis here, the modeled impacts must be seen as indicative of the possible load responses rather than predictive. Additional pilots designed to specifically investigate California residential responses to particular rate designs are needed.

Even with this caveat, the modeling performed suggest some possible responses. First, conventional residential TOU rate designs, such as those in place and those currently proposed, can reduce summer peak demands on the order of hundreds of megawatts. But in order to get more than about 100 MW reduction, high participation is required, such as from having the TOU rates be default. Second, the current and currently-proposed TOU rates will likely induce little to no additional use during spring afternoons when the CAISO predicts possible over generation events.

When MRW considered hypothetical rates designed to align with the CAISO's load profile and with very aggressive TOU price differentials, the modeling suggests much greater load impacts could occur, on the order of 1,000 MW to 1,500 MW. However, the modeling suggests that even with targeted TOU periods aggressive rate design, only modest increases in residential loads during periods where over generation is being predicted. Pilots designed to explore if or how residential rate designs can shift load into key periods are needed to better understand consumer response in these circumstances.

1. Introduction

The California Energy Commission (CEC), the California Independent System Operator (CAISO), and the California Public Utilities Commission (CPUC) staff, together as the Joint Agency Steering Committee (JASC), are collaborating on a supplemental analysis to the 2015 Integrated Energy Policy Report (IEPR) baseline forecast that examines the potential load impacts of possible changes to time varying rates and other rate design elements. In support of this effort, MRW & Associates, LLC (MRW) was retained by the CEC to examine the available literature on the impact of residential TOU rate designs on load and to use the demand elasticities observed in the literature to model the impact of a several time-of-use (TOU) rate design scenarios on residential demand and energy usage.

The impetus for the study is twofold. First, as with many jurisdictions, the JASC is interested in better understanding the potential summer peak-demand reduction that could be induced by higher on-peak residential rates. Second, the JASC, and CAISO in particular, is interested in to what degree TOU rates could be used to address the belly of the "duck curve." [3] That is, on spring afternoons when solar output is high and usage is modest, could providing residential electricity users a price signal (low rates) to consume more during these hours help stave off potential over-generation events and renewable curtailment?

1.1 Literature Review

MRW was asked to conduct a literature review examining the peak demand and energy usage impacts observed from residential TOU pilot programs in other jurisdictions. MRW focused on studies with the most relevance to California's three major investor-owned utilities (PG&E, SCE, and SDG&E), and evaluated studies based on the implications for California's residential demand and energy usage forecasts. MRW used data from the literature to determine estimations of daily and substitution elasticity to utilize the TOU rate impact model.

The methodology and results of the literature review are discussed in the following section of this report. In-depth summaries of the most relevant studies and summary table are provided in Appendix A of this report.

1.2 TOU Rate Impact Model

Using the measurements of elasticity determined in the literature review, MRW developed a model to simulate changes in hourly load for six TOU rate design scenarios, prepared by the CPUC and agreed to by the CAISO and CEC staff. The model analyzes anticipated electricity demand impacts from TOU rates for the base year of 2021 and over several additional years with an escalation in load for an assumed growth rate, providing both a base case and an "expected+" case (representing a more optimistic outlook). The model forecasts the peak demand and on-peak energy usage reductions that can be anticipated in each year for each of California's three major public utilities from implementation of the TOU rates under each of these scenarios, as

[3] E.g., CAISO, "Demand Response and Energy Efficiency Roadmap: Maximizing Preferred Resources," December, 2013.

well as changes to mid-peak and off-peak demand and energy usage that can be anticipated from the shift to TOU rates.

2. Literature Review

2.1 Background & Methodology

The CEC, CAISO, and CPUC joint staff are collaborating on a supplemental analysis to the 2015 IEPR baseline forecast that would examine potential load impacts of possible changes to time varying rates and other rate design elements. In support of that effort, MRW conducted a literature review on the demand and energy usage impacts observed from residential TOU pilot programs and residential TOU tariffs in other jurisdictions. Ultimately, MRW was tasked with finding estimations of daily and substitution elasticities to be used in the TOU rate impact model.

The literature search focused pilot programs and studies that met the following criteria:

4. Were published in the last ten years (i.e., since 2006);
5. Were relevant to California climates; and
6. Provided quantitative results.

Exceptions to these criteria were made for particularly relevant studies such as the Charles River Associates *Impact Evaluation of the California Statewide Pricing Pilot*, which was published in 2005. Because even these relatively broad categories significantly narrowed the pool of applicable studies, MRW also included studies from overseas as well as pilots that looked at critical peak pricing (CPP). Over 48 studies were identified as potentially useful, and the most relevant 33 were summarized. Included in each report summary, presented in Appendix A of this report, is an assessment of the applicability of the results to the modeling phase of the Joint Agency Supplemental Rate Analysis supporting the 2015 IEPR.

2.2 Results

Of the 33 potentially applicable studies summarized, few studies provided useful estimations of elasticity upon which to base the TOU rate impact model. For example, only 12 studies explicitly addressed the impacts of residential TOU rates on usage patterns, either in the form of an estimated elasticity, or, as was more common, in percentage changes in estimated demand and/or energy usage as a result of TOU. Of these 12 studies, three studies, summarized in Table 15 in Appendix A, were meta-studies summarizing results from multiple pilots, including some conducted in Europe and Oceania. The other nine were specific pilot studies, two of which were California-specific (SMUD and the 2003-2004 California Statewide Pricing Pilot), one from Arizona, and the remaining from the Northeast.

Overall, the reported elasticities varied significantly. Estimations of own-price elasticity ranged by over an order of magnitude, from a -0.65 to 0.26 range observed in the Salt River Project (SRP), to -0.003 observed in the California Statewide Pricing Pilot (SPP). Estimations of substitution elasticity varied from -0.081 as observed in the SPP, to 0.131 observed by SMUD.

Variations in reported elasticity varied significantly from study to study due to the following variations in pilot program design:

- The TOU periods presented in the studies were generally relatively broad, from six to eight hours, encompassing summer afternoons and going into the early evenings. Only the 2012-2013 Smart Pricing Options Pilot for the Sacramento Municipal Utility District (SMUD), and the 2008 SRP Experimental TOU Price Plan utilized narrow three-hour peak periods, from 4:00 to 7:00 p.m. and 3:00 to 6:00 p.m., respectively. The recent 2013-2014 PECO Smart Time Pricing pilot utilized a four-hour TOU period from 2:00 to 6:00 p.m.

- Most pilots required customers to opt-in (creating a self-selection bias), with some programs imposing minimum consumption requirements for participation. SRP, whose pilot was opt-in and limited to higher-use customers (monthly consumption over 1,800 kWh) reported the highest elasticity with reductions to average summer peak load of approximately 25%.

- Many studies assessed the impact of TOU with and without enabling technologies, such as smart thermostats, in-home displays such as energy orbs, and air-conditioning cycling switches. Generally, the greatest reductions from TOU came for customers with air conditioning and some kind of in-home enabling device.

- Some studies included both a combination critical peak pricing (CPP) and TOU program design. The reported daily elasticities for SMUD's joint CPP and TOU program with enabling technology devices were on the order of -0.05 to -0.1, with a substitution elasticity of -0.040.

- While many studies reported that off-peak consumption increased (i.e., load-shifting), none addressed wither there was a marked increase immediately following the end of the peak TOU period.

- Most addressed only impacts on summer peak demand. Only a very few reported winter / non-summer results. First, one, can infer some winter elasticity estimates from the PECO Smart Time Pricing Pilot. Second, the report on California's 2003-2004 SPP reported seasonal elasticities.

- None of the studies considered rates with three TOU periods.

3. Price-Response Modeling Assumptions

A key task in the project was to glean from the literature review appropriate elasticities to use on the California modeling. The challenge was that there were no studies that were directly applicable to the task at hand. Good, recent data, such as from the recent SMUD pilots, were summer-only, or took place in areas where climates and electric use were inapplicable to California. A study for a utility serving the Philadelphia area, for example, provided the most recent statistics on electric demand related TOU, however the pilot program was marketed to customers that had chosen to remain with utility service rather than seek power from independent retail suppliers, in a very competitive market place. Additionally, the characteristics of a Philadelphia-based sample population, which is highly urban with a greater prevalence of air conditioning in single-family homes, are not consistent with a typical California customer. Furthermore, statistics derived from a study with such demographic differences from California, if applied this study could impact the relative impacts observed in the spring, winter, and summer.

Given the lack of availability of recent elasticity data applicable to California, MRW choose to use daily and substitution elasticity inputs and methodology for assessing impacts on residential demand, presented in Charles River Associates' Impact Evaluation of the California Statewide Pricing Pilot report on California's 2003-2004 SPP. While this study is among the older of those reviewed, it is the only comprehensive study of California to date, and is the most appropriate study reviewed to California climate and customers.

3.1 Price Elasticity Model

MRW used the constant elasticity of substitution (CES) model to estimate price responses. The CES model consists of two equations. The first equation reflects the ratio of peak to off-peak quantities, expressed in logs, as a function of the ratio of peak to off-peak prices, also expressed in logs, plus other terms, as appropriate.[4] The second equation models "daily" electricity consumption, expressed in logs, as a function of the daily price of electricity, also expressed in logs, and other factors. The daily elasticity reflects that when time-of-use periods are implemented, the average rate in a day can differ from the annual average flat rate. For example, summer weekdays will have a higher average rate than the annual average rate, and thus induce decreased usage that is independent of the TOU rates in place. The two equations constitute a system for predicting electricity consumption by rate period.

Given that MRW was not considering "other terms," the CES equations simplifies to the following:

$$Q' = \mathrm{Q} \cdot \left(\frac{\mathrm{p}'}{\mathrm{p}}\right)^{\alpha}$$

Where:

[4] E.g., household income, climate, presence of air conditioning or electric heating, etc.

Q = average daily consumption, flat rate

Q' = average daily consumption with TOU

p = average daily price, flat rate

p' = average daily price with TOU

α = daily elasticity of demand

and

$$Q_1' = \frac{Q_1}{Q_2} \cdot \left(\frac{p_1'}{p_2'}\right)^{\eta}$$

Q_1 = average daily consumption in off-peak period with flat rate

Q_2 = average daily consumption in peak period with flat rate

Q_2' = average daily consumption in peak period with TOU

p_1' = average off-peak price

p_2' = average peak price

η = substitution elasticity of demand

When a three-period TOU rate is considered, an additional equation is added

$$Q_2' = \frac{Q \cdot (H_1 + H_2 + H_3)}{\frac{Q_1}{Q_2} \cdot \left(\frac{p_1'}{p_2'}\right)^{\eta} \cdot H_1 + H_2 + \frac{H_3}{\frac{Q_2}{Q_3} \cdot \left(\frac{p_2'}{p_3'}\right)^{\eta}}}$$

Where:

Q_2' = average daily consumption in medium-price period with TOU

$H_{1,2,3}$ = Number of hours low, medium, high price periods, respectively

$Q_{1,2,3}$ = average daily consumption in low, medium, high price periods, respectively, with flat rate

$p'_{1,2,3}$ = Prices in low, medium, high price periods, respectively

The average daily flat rate is the simple average of the volumetric rate charge (i.e., no tiers). Because the assumed TOU rates are seasonal, the overall summer price level is typically higher on the TOU rate than the non-TOU flat rate, leading to small reductions in the overall usage level during that season (and vice versa in the winter).

3.2 Base Case Scenario Elasticity Assumptions

Given the use of the CES model to estimate price response, the MRW used the most relevant estimations of daily and substitution elasticity presented in the TOU pilot program literature reviewed, and described in greater detail below, as the basis for the TOU rate impact model.

3.2.1 Daily Price Elasticity

The estimations of daily price elasticities presented in Charles River Associates' *Impact Evaluation of the California Statewide Pricing Pilot* report on California's 2003-2004 statewide pilot program (SPP) were used as the basis for assessing the impact of changes in TOU rates on energy demand and usage in the TOU rate impact model. While this study is among the older of those reviewed, it is the only comprehensive study of California to date, and it presents estimations of daily elasticity by season. While other studies provided daily elasticity, this study was the most appropriate to California climate and customers.

3.2.2 Substitution Elasticity

Similar to the daily price elasticity, the estimates of substation elasticity from the SPP were used to assess the shift in demand and energy usage from peak to off-peak (or super-off-peak to off-peak, etc,) in response to TOU rate design. The estimates of daily and substitution price elasticities presented in the SPP were used to inform MRW's model. As previously noted, these estimations of elasticity were most applicable to the California climate and customers, and were provided for each season so as to be useful as inputs into a CES model.

MRW used the four seasonal daily and substitution elasticities presented in the study for the Critical Peak Pricing (CPP)-F rate for a normal weekday. These elasticities were preferred to the TOU rate results because they were the most robust of the study, with the least rate impact variation and sample size limitations.[5]

Table 1: SPP Price Elasticity Estimations used in MRW Model[6]

Season	Months	Daily Price Elasticity	Substitution Elasticity
Inner Winter	December, January, February	-0.003	-0.033
Outer Winter	November, March, April	-0.043	-0.012
Inner Summer	July, August, September	-0.042	-0.081
Outer Summer	June, October	-0.050	-0.036

[5] SPP, p. 10.
[6] SPP, pp. 53, 54, and 79.

However, not all of the rate designs had seasonal definitions that matched that of the SPP. In these cases, MRW blended each of the four elasticities presented in the study to account for overlaps between months and seasons among the defined Scenarios 5 and 6 and the SPP. For example, the CAISO defined the spring season in Scenarios 5 and 6 as consisting of the months of March and April, whereas the SPP defines "Outer Winter," equivalent to spring, as the months of November, March and April. The difference in monthly definitions is due to the observed months which don't include HVAC responses. Therefore, blended elasticities accounting for the seasonal overlaps of months as defined by season were applied in the model for each appropriate month.

3.3 Expected+ Scenario

While the Expected+ Scenario uses the same daily price elasticity inputs as the Base Case Scenario, the estimate of substitution elasticity from the SPP has been modified to account for the increases in demand response observed when TOU is paired with enabling technologies.

In *Arcturus: An International Repository of Evidence on Dynamic Pricing* (Faruqui and Sergici 2014), the authors note that enabling technologies such as smart thermostats, energy orbs, and in-home displays, which either automate actions for customers or provide customers with information to act on, can increase demand response by approximately over 100%.[7] For example, the authors estimate that for a price ratio of 2:1, the expected TOU peak reduction related to a price-only increase versus a price increase with enabling technology is 4.7 and 9.4%, respectively. Therefore, for the Expected+ Scenario, described in greater detail in the following section, MRW assumed that reductions in peak energy usage will increase by 100% when paired with enabling technology, and have implemented this in the model by doubling the substitution elasticity for the Expected+ Scenario. Specifically, for this scenario we have assumed that 30% of customers have adopted enabling technology.

Table 2. Assumptions Base Case vs. Expected+

Assumption	Base Case	Expected+
Technology	No enabling technology	30% of participants use enabling technology
Customer Response		100% greater than Base Case for those using enabling technology

[7] Ahmad Faruqui and Sanem Sergici, Arcturus: An International Repository of Evidence on Dynamic Pricing, p. 70.

3.4 Sensitivity

As noted, there is very little data on residential prices response during non-peak periods. Because the potential for increasing load during spring afternoons was of particular interest to the JASC, MRW also investigated what would happen if significantly higher substitution elasticities were applied. Specifically, MRW also examined the impact on low-use spring days using a much higher substitution elasticity, -0.066 rather than -0.012, on the residential load shape.

4. Modeling Methodology

The TOU rate impact model consists of two components: a residential load forecast model and a rate impact model. A separate load forecast was prepared for each of the three IOUs.

4.1 Residential Load Forecast Model Methodology

The starting point for the residential load forecast model for each utility is the utility's 2012 hourly residential sales, as reported by the utility. To obtain total residential electricity load, 2012 behind-the-meter residential solar output is added to the utility's sales. Residential load forecasts developed as part of the Energy Commission's Integrated Energy Policy Report (IEPR) process are then used to scale 2012 total residential load to 2024 forecasted load, with the increase to usage in 2025 estimated based on the 2019-2024 average residential growth rate from the IEPR forecast. Finally, a forecast of hourly residential solar output in each of the years 2016-2025 is subtracted from the residential load forecast to obtain an hourly forecast of residential utility sales in each year. More detail about each of these steps is provided below.

4.1.1 Hourly Residential Electric Loads, 2012

The utilities each publish dynamic load profiles on their websites, which provide hourly sales data for each customer grouping, on either a per-customer basis or a consolidated basis. The available information is available as follows:

- Pacific Gas & Electric (PG&E): Residential hourly load profiles beginning January 2000 may be downloaded from the webpage http://www.pge.com/nots/rates/tariffs/energy_use_prices.shtml by selecting "E-1, E-8, E-13" in the drop-down menu. These data are provided on a per-customer basis. To obtain total residential sales, the average per-customer sales are multiplied by the number of PG&E residential customers, obtained from PG&E's 2012 Form 1 filing to the Federal Energy Regulatory Commission (FERC).

- Southern California Edison (SCE): Residential hourly load profile for 2012 may be downloaded from the webpage https://www.sce.com/005_regul_info/eca/DOMSM12.DLP. These data are provided on a per-customer basis. To obtain total residential sales, the average per-customer sales are multiplied by the number of SCE residential customers, obtained from SCE's 2012 FERC Form 1 filing.

- San Diego Gas & Electric (SDG&E): Hourly load profiles for the last 12 months for each customer grouping may be downloaded from the webpage http://www2.sdge.com/eic/dlp/DownloadRange.cfm by selecting "Most Recent Year" in the drop-down menu. These data are provided on a consolidated basis for the entire customer grouping, with total residential sales provided in the "Residential" grouping. Data for 2012 SDG&E in 2012 was provided by CEC Staff.

To obtain hourly residential electric loads, residential behind-the-meter solar photovoltaic (PV) output is added to the hourly residential electric utility sales. The hourly PV forecasts are discussed in Section 4.1.3 below.

4.1.2 Hourly Residential Electric Loads, 2016-2025

Hourly electric loads for 2016-2025 for residential customers of PG&E, SCE, and SDG&E are forecast starting from the utilities' 2012 hourly load profiles by using scaling factors derived from the Energy Commission's April 2014 California Energy Demand Mid-Case IEPR forecasts.[8] The following steps are used to derive the scaling factors for 2016-2024:

1. Start with the residential electricity consumption ("load") forecast in Demand Forecast Form 1.1 for the applicable planning area.

2. To obtain the gross electricity load forecast for residential customers of the utility from the planning area-wide forecast, scale the planning area forecast by the share of electricity sales in the planning area that is applicable to that utility, as calculated from Form 1.1c of the statewide Demand Forecast Form.[9]

3. To obtain the net residential load forecast for each year, subtract from the gross forecast the IEPR forecast of additional achievable energy efficiency (AAEE), obtained from Form S3-Mid of the AAEE Savings Demand Forecast Form for the applicable utility service territory.[10]

4. To obtain the average hourly residential load in each year, divide the annual net residential load forecast by 8,760 hours per year.

5. To obtain the load-growth scaling factor, evaluate the change in the average hourly residential load compared to the actual or forecast average hourly load in the prior period.

[8] California Energy Demand, 2014-2024, Mid-Case Final Baseline Demand Forecast Forms, April 2014, available at http://www.energy.ca.gov/2013_energypolicy/documents/#adoptedforecast

[9] Electricity Deliveries to End Users by Agency (GWh), Mid-demand and mid-AAEE savings.

[10] Available at http://www.energy.ca.gov/2013_energypolicy/documents/demand-forecast_CMF/Additional_Achievable_Energy_Efficiency/

6. To obtain an hourly load forecast that is consistent with the IEPR forecast of total residential load, apply the load-growth scaling factor to the prior period's forecast of hourly loads.

7. For consistency with the IEPR forecast of peak load, make the following peak load adjustment:

    a. Calculate the IEPR peak demand forecast by subtracting the AAEE peak demand savings from Form 1.1c of the statewide Demand Forecast Form from the forecast of residential coincident peak demand in the utility's planning area, obtained from Demand Forecast Form 1.3.

    b. Calculate the difference between the IEPR peak load forecast (see Step 7a) and the IEPR average load forecast (see Step 4). Do this for both the forecast period and the prior period.

    c. Compare the difference between the peak load forecast and the average load forecast from the prior period to the forecast period. The growth (or reduction) in this metric is the peak load adjustment factor.

    d. For each hourly load in the forecast period, add an adjustment factor that is calculated as the peak load adjustment factor multiplied by the difference between the hourly load and the average hourly load forecast for that year.

For 2025, which is not included in the IEPR forecast, the compound annual growth rate of the load growth scaling factor (Step 5) over the years 2019-2024 is applied to the 2024 load forecast. No peak load adjustment is applied.

4.1.3 Hourly solar output

Hourly residential behind-the-meter solar output is estimated based on the California Energy Commission's recorded and forecast "Mid Demand" values for energy output for residential PV by climate zone, developed for the 2015 IEPR demand forecast.[11] Since these climate zones include areas that are outside the utilities' service territories, data on solar installations in the utilities' service territories from the Go Solar California website are used to estimate the share of residential PV within an area that is attributable to the utility's customers. For example, the climate zones applicable to PG&E are Zones 1-5.[12] The IEPR data indicate that there were 316 MW of residential PV in these climate zones in 2012. The Go Solar California Website indicates that PG&E customers installed 256 MW of residential PV from 2006-2012.[13] From here, it is

[11] California Energy Commission. Residential PV by Climate Zone, California Energy Demand Updated Forecast, 2015-2025. Data obtain from CEC Staff.
[12] Zones 7-10 are applicable to SCE's service area, and Zone 13 is applicable to SDG&E's service area. Source: California Energy Commission.
[13] Data obtained on May 27, 2015, from the website, https://www.californiasolarstatistics.ca.gov/reports/agency_stats.

estimated that 81% of residential PV output in Zones 1-5 originates from PG&E customers,[14] estimated to apply both in 2012 and in each of the forecast years. To obtain annual PV output for PG&E residential customers, the IEPR recorded or forecast values for PV output in Zones 1-5 is therefore scaled by 81%.

To develop hourly solar output profiles consistent with these annual data, the National Renewable Energy Laboratory's "PVWatts" model is run for a representative city for the utility's service area.[15] The PV system size used in the model is set such that the sum of the hourly outputs over the year is equal to the annual PV output estimated based on the IEPR data and the Go Solar California data. These PVWatts hourly profiles are developed for the 2012 starting year and for the 2021 base year; for other years, hourly solar profiles are scaled based on the IEPR forecast of residential PV output for that planning area.

Solar output is added to the utilities' 2012 sales data to obtain total 2012 loads. Solar output is later subtracted from forecast load data to obtain forecasts of utility sales at the meter.

4.2 Modeled Scenarios

MRW modeled six TOU rate scenarios for each of the IOUs, defined by the JASC. The scenarios, described in detail below, vary by TOU periods, customer participation (% opt-in), and defined rates.

4.2.1 TOU Peak Periods and Customer Participation

Table 3 below provides a breakdown of each of the six scenarios defined by the JASC modeled here. Scenario 1 assumed current TOU periods, with a with 10% customer participation achieved by 2021. Scenarios 2, 3, and 4 assume the TOU periods presently proposed by the IOUs, with customer participation increasing in intervals to 10%, 30%, and 80% (the assumed participation for default TOU) by 2021, respectively. Scenarios 5 and 6 assume TOU periods defined by the CAISO, with customer participation of 80% to 30% by 2021, respectively.

[14] 81% = 256 MW/316 MW.

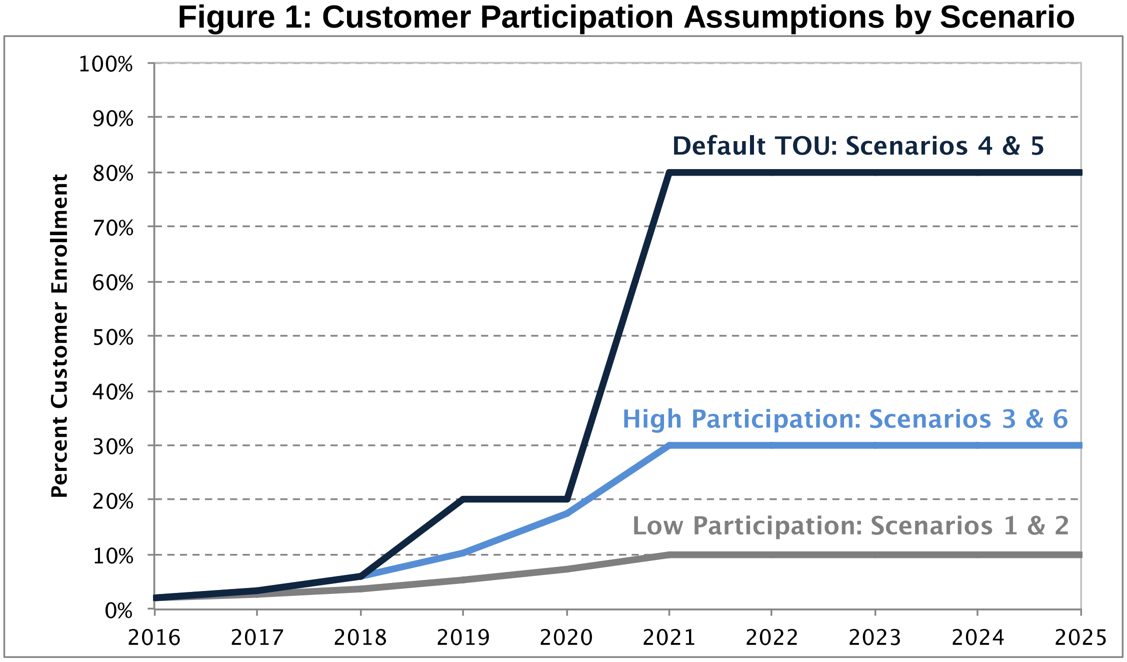
[15] The PVWatts model is available at http://pvwatts.nrel.gov/pvwatts.php.

Table 3: JASC Rate Scenario Participation and TOU Peak Periods

Scenario	Description	Customer Opt-In Rate	TOU Peak Periods		
			PG&E	SCE	SDG&E
Scenario 1	Current TOU, Low Participation	10% by 2025	12 pm – 6 pm (current)	12 pm – 6 pm (current) 2 pm – 8 pm (optional rate)	11 am – 6 pm (current)
Scenario 2	IOU Proposed, Low Participation	10% by 2025	4 pm – 9 pm (proposed)	2 pm – 8 pm (effective 2019)	2 pm – 9 pm (proposed)
Scenario 3	IOU Proposed, High Participation	30% by 2025			
Scenario 4	IOU Proposed, Default TOU	80% by 2025			
Scenario 5	CAISO Proposed, Default TOU	80% by 2025	12 pm – 4 pm (July and August) 4 pm – 9 pm (all other months)		
Scenario 6	CAISO Proposed, High Participation	30% by 2025			

As illustrated in Figure 1 the model assumes that full customer participation per scenario is achieved 5 years into the study in 2021 (i.e. customer participation for Scenario 5 will reach full participation at 80% by 2021, meeting the defined 2025 target). Additionally, model assumes trended increase to final state by 2021, with the exception of the default TOU scenarios simulates what might happen in the 30% opt-in scenarios in 2016-2018 then in 2019 and 2020 you have a large pilot program with 20% adoption. While in general the data presented in the report is for 2025, full year-by-year results are included in Appendix B.

Figure 1: Customer Participation Assumptions by Scenario



4.2.1 Rates

The tables below provide the JASC-approved rates by utility for each of the six scenarios. Scenario 1 assumes current TOU rates, while Scenarios 2, 3, and 4 assume the TOU periods and rates presently proposed by the IOUs. The rates for Scenarios 5 and 6 assume TOU periods defined by the CAISO, and conceptual rates defined by the CPUC. These rates were designed to be revenue neutral and provide very strong price signals during system peak hours: very high prices during the "inner summer" late afternoons and early evenings (super-peak), and very low prices during the springtime and winter early-to-mid afternoons (super off-peak). It must be emphasized that the extreme rates used Scenarios 5 and 6 are to explore the potential for price-response, and have not been proposed by any utility or contemplated by the CPUC. The CAISO seasonal definitions are consistent with those presented in

Table 5, starting in 2020.[16]

Each of the six scenarios assumes a monthly fixed charge of $10.

Table 4: PG&E Non-CARE Rates by Scenarios 1 thru 4 (¢/kWh)

Season	TOU Period	Scenario 1 TOU Periods (Current TOU, Low Participation)	Scenario 1 Rates	Scenarios 2, 3, and 4 TOU Periods (IOU Proposed Low-, Mid-, and Default Opt-In)	Scenarios 2, 3, and 4 Rates	Fixed Charge ($/month)
Summer	Peak	1 pm – 7 pm, Weekdays	37.3	4 pm – 9 pm, Weekdays	31.0	$10
	Partial-Peak	10 am – 1 pm, Weekdays 7 pm – 9 pm, Weekdays 5 pm – 8 pm Weekends	25.8	n/a	n/a	
	Off-Peak	All other hours, including holidays	18.1	All other hours, including holidays	20.7	
Winter	Peak	n/a	n/a	4 pm – 9 pm, Weekdays	17.5	$10
	Partial-Peak	5 pm to 8 pm, Weekdays	19.2	n/a	n/a	
	Off-Peak	All other hours, including holidays	17.6	All other hours, including holidays	15.6	

[16] April 8 Levin presentation p. 6, cites to March 12, 2015 public release by CAISO of suggested TOU period definitions for 2020 and beyond.

Table 5: CAISO Proposed Seasons for Scenarios 5 and 6

Season	Months
Winter	November, December, February
Spring	March, April
Outer Summer	May, June, September, October
Inner Summer	July August

Table 6: PG&E Non-CARE Rates by Scenarios 5 and 6 (¢/kWh) [17]

	Season	Super Peak 4 pm – 9 pm	Peak 12 pm – 4 pm (Inner Summer) 4 pm to 9 pm (All other seasons)	Off-Peak 12 am – 4 pm 9 pm – 12 am	Super Off-Peak 10 am – 4 pm
Weekday	Winter	n/a	16.0	13.2	n/a
	Spring	n/a	30.7	12.1	7.5
	Outer Summer	n/a	37.3	13.6	n/a
	Inner Summer	60.0	27.9	13.2	n/a
Weekend		No hours	4 pm to 9 pm	12 am – 10 am 9 pm – 12 am	10 am – 4 pm
	Winter	n/a	15.9	13.6	7.5
	Spring	n/a	14.6	12.3	7.5
	Outer Summer		18.7	13.0	7.5
	Inner Summer	n/a	22.6	13.7	n/a

[17] Revenue neutral rates provided to MRW by CPUC Energy Division staff.

Table 7: SCE Non-CARE Rates by Scenarios 1 thru 4 (c/kWh)[18]

Season	TOU Period	Scenarios 1, 2, 3, and 4 TOU Periods	Scenarios 1 2, 3, and 4 Rates	Fixed Charge ($/month)
Summer	**Peak**	2 pm – 8 pm, Weekdays	36.6	$10
	Off-Peak	All other hours, including holidays	19.8	
	Super Off-Peak	10 pm – 8 am, Everyday	11.3	
Winter	**Peak**	2 pm – 8 pm, Weekdays	26.5	$10
	Off-Peak	All other hours, including holidays	15.9	
	Super Off-Peak	10 pm – 8 am, Everyday	11.3	

Table 8: SCE Non-CARE Rates by Scenarios 5 and 6 (¢/kWh)[19]

		Super Peak	Peak	Off-Peak	Super Off-Peak
Weekday	**Season**	**4 pm – 9 pm**	**12 pm – 4 pm (Inner Summer) 4 pm to 9 pm (All other seasons)**	**12 am – 4 pm 9 pm – 12 am**	**10 am – 4 pm**
	Winter	n/a	17.7	14.8	n/a
	Spring	n/a	33.1	13.8	7.5
	Outer Summer	n/a	39.9	15.2	n/a
	Inner Summer	60.0	29.7	14.8	n/a
Weekend		**No hours**	**4 pm to 9 pm**	**12 am – 10 am 9 pm – 12 am**	**10 am – 4 pm**
	Winter	n/a	17.7	15.2	7.5
	Spring	n/a	16.2	14.0	7.5
	Outer Summer	n/a	20.7	14.7	7.5
	Inner Summer	n/a	24.6	15.5	

[18] As noted in the Christensen Report, SCE's proposed rates have been approved and therefore the rates for Scenarios 1 and 2 are the same (Christensen, p. 4).
[19] Revenue neutral rates provided to MRW by CPUC Energy Division staff.

Table 9: SDG&E Non-CARE Rates by Scenarios 1 thru 4 (¢/kWh)

Season	TOU Period	Scenario 1 TOU Periods	Scenario 1 Rates	Scenarios 2, 3, and 4 TOU Periods	Scenarios 2, 3, and 4 Rates	Fixed Charge ($/month)
Summer	Peak	11 am – 6 pm, Weekdays	31.051	2 pm – 9 pm, Weekdays	26.562	$10
	Partial-Peak	6 am – 11 am, Weekdays 6 pm – 10 pm, Weekdays	25.196	6 am – 2 pm, Weekdays 9 pm – 12 am, Weekdays 6 am – 12 am, Weekends	22.881	
	Off-Peak	All other hours, including holidays	21.022	All other hours, including holidays	17.276	
Winter	Peak	5 pm – 8 pm, Weekdays	24.659	5 pm – 9 pm, Weekdays	21.142	$10
	Partial-Peak	6 am to 5 pm, Weekdays 8 pm – 10 pm, Weekdays	23.184	6 am – 5 pm, Weekdays 9 pm – 12 am, Weekdays 6 am – 12 am, Weekends	19.435	
	Off-Peak	All other hours, including holidays	21.139	All other hours, including holidays	17.631	

Table 10: SDG&E Non-CARE Rates by Scenarios 5 and 6 (¢/kWh)[20]

	Season	Super Peak	Peak	Off-Peak	Super Off-Peak
Weekday		4 pm – 9 pm	12 pm – 4 pm (Inner Summer) 4 pm to 9 pm (All other seasons)	12 am – 4 pm 9 pm – 12 am	10 am – 4 pm
	Winter	n/a	25.6	22.8	n/a
	Spring	n/a	35.3	21.9	7.5
	Outer Summer	n/a	41.4	22.8	n/a
	Inner Summer	60.0	34.8	22.9	n/a
Weekend		No hours	4 pm to 9 pm	12 am – 10 am 9 pm – 12 am	10 am – 4 pm
	Winter	n/a	25.7	23.3	7.5
	Spring	n/a	24.2	22.1	7.5
	Outer Summer	n/a	27.8	22.7	7.5
	Inner Summer	n/a	31.6	23.4	n/a

20 Revenue neutral rates provided to MRW by CPUC Energy Division staff.

5. Base Case Modeling Results

5.1 Scenarios 1 to 4: Conventional Pricing

Error! Reference source not found. below shows the summer change in peak load (MWh) and peak demand (MW) achieved from TOU rates in 2025. (Full details for each year and scenario are in Appendix B.) As is shown in the tables, under the IOUs' proposed scenarios, reductions in peak load and demand increase as customer participation grows. The greatest reductions to load and demand is achieved in Scenario 4 with default TOU customer enrollment. Even under high enrollment, however, total reductions in peak demand range only from 1.2-4.2%.

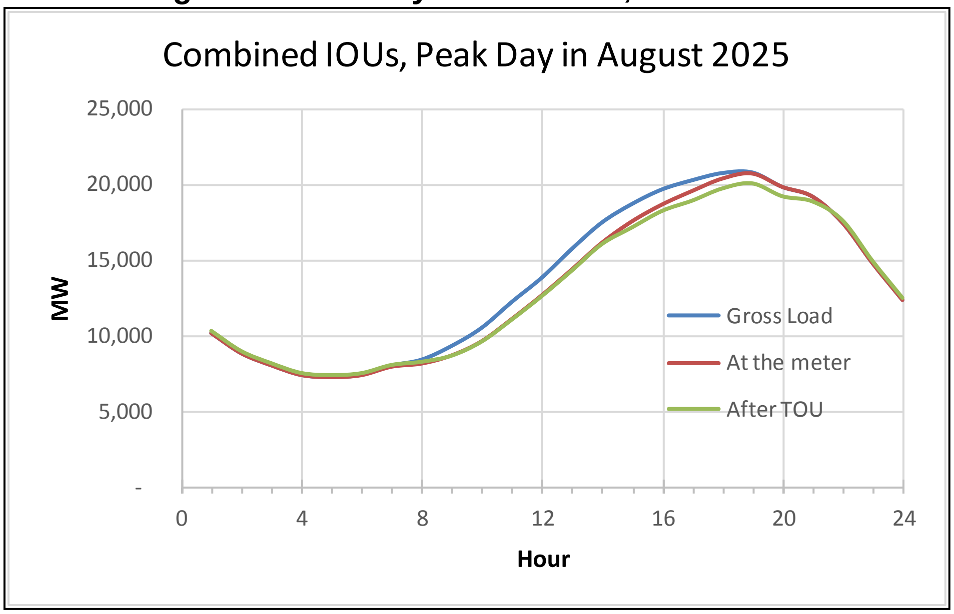
For SCE and SDG&E, reductions in peak load result in some conservation, with the remaining peak load savings shifting into the off-peak period. Overall, reductions in summer peak consumption for these utilities result in similar increases in off-peak consumption, increasing with customer participation. The opposite impact is seen for PG&E. Off-peak reductions for PG&E increase as peak reductions increase. This is the result of both conservation and PG&E's differing proposed rate structure.

Table 11. Weekday Summer Impacts Scenarios 1-4, 2025

Scenario	Description	Change in Load (MWh)		Change in Peak (MW)	% Change in Peak
		Peak	Off Peak		
PG&E					
Scenario 1	Current TOU, Low Participation	-13,120	+7,562	-32	-0.3%
Scenario 2	IOU Proposed, Low Participation	-8,043	-3,176	-29	-0.3%
Scenario 3	IOU Proposed, High Participation	-24,129	-9,527	-88	-0.9%
Scenario 4	IOU Proposed, Default TOU	-64,343	-25,406	-234	-2.4%
SCE					
Scenario 1	Current TOU, Low Participation	-15,900	+13,971	-48	-0.5%
Scenario 2	IOU Proposed, Low Participation	-15,900	+13,971	-48	-0.5%
Scenario 3	IOU Proposed, High Participation	-47,701	+41,912	-143	-1.6%
Scenario 4	IOU Proposed, Default TOU	-127,202	+111,766	-382	-4.2%
SDG&E					
Scenario 1	Current TOU, Low Participation	-1,919	+1,460	-4	-0.2%
Scenario 2	IOU Proposed, Low Participation	-1,695	+1,327	-3	-0.1%
Scenario 3	IOU Proposed, High Participation	-5,086	+3,981	-9	-0.4%
Scenario 4	IOU Proposed, Default TOU	-13,561	+10,617	-23	-1.2%

Summer peak (weekday). Figure 2 below, shows the CAISO-wide (all three IOUs) peak day hourly residential demand (August 13 using the data analyzed here). Three lines are shown. The top blue line shows the gross usage of the residential class under flat rates, prior to any solar PV is taken into account. This is load to which the CES elasticity formulae are applied. The second, red line shows the load at the meter, after accounting for behind the meter solar PV. The third, generally bottom line, is the load at the meter after the TOU rates have been applied. The figure is from Scenario 4 (default TOU with IOU proposed TOU periods) so as to make the impacts more visible.

Figure 2. Peak Day Load Profile, Scenario 4.

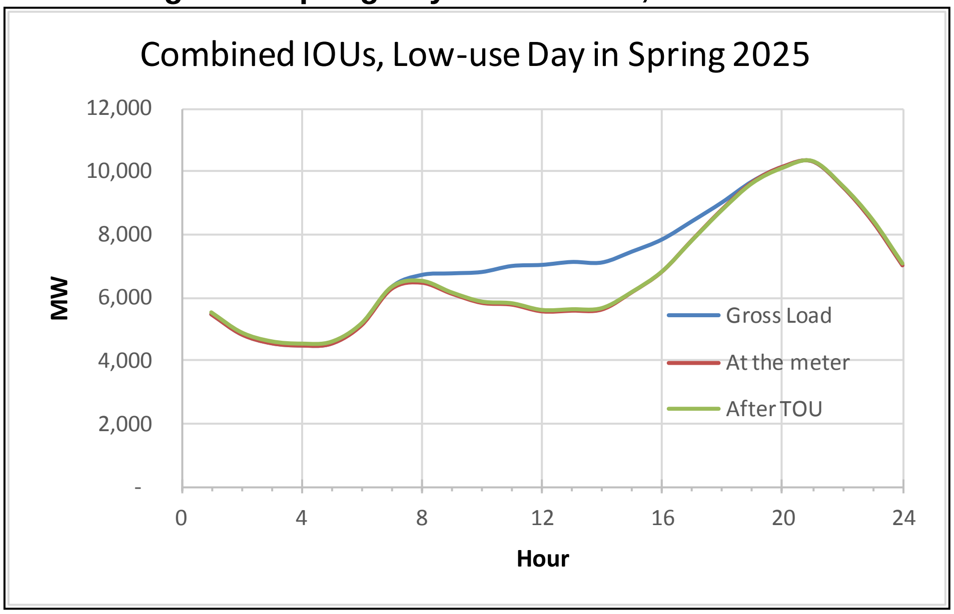


A number of insights can be gleaned from Figure 2. First, and most clear, is the decrease during the peak hours. At its maximum at 7:00 pm, the model suggests that the TOU rate would decrease the peak demand by approximately 630 MW. While not insignificant, it is still relatively small on a percentage basis (~ -3%). Second, during the middle of the day the TOU has negligible impact, with the After TOU line overlapping with the "At the meter" line. Last, one can see a small uptick in usage during the off-peak hours, on the order of a few tens of megawatts.

Spring weekday. Figure 3 shows an analogous graph for a typical spring weekday. Ideally, the TOU rate would induce customers to consume more during the mid-day hours so as to minimize over-generation and the curtailment of utility-scale renewables. From this figure, one can see the beginning of the "belly" of the duck curve, with a marked decrease in load at the meter from approximately noon to about 3:00 pm. As one would expect from the assumptions underlying Figure 2, the model shows that the impact during that period is minimal, increasing the load by only about 20 MW. This is due to primarily to the fact that the rates were not designed to impact these spring hours: there is no "spring" seasonal rate, and the TOU periods are not aligned. For example, SCE is charging its peak rates during that time, incenting customers to conserve. While PG&E's spring afternoon hours are during its off-peak rate, the size of the peak TOU period is small—4 hours—and the price differential very modest: 1.12:1. SDG&E's rates, while having three TOU periods rather than the two for PG&E, are in other respects similar to PG&E: the partial-peak period is very broad and the price differential modest (1.09:1).

Given these facts, it is not surprising that then that using the aggressive off-peak elasticity of substitution, -0.066 rather than the base -0.012, has almost no effect: the increases in load from SCE's incentives to decrease load balances out the incentives to increase load by the other two utilities.

Figure 3. Spring Day Load Profile, Scenario 4



Because load shapes and pricing is different on weekends MRW also considered the impacts of the TOU rates during the same spring period. (Summer is not discussed, as the goal of TOU then is to decrease system peak loads, which occur strongly on weekdays. Nonetheless, the basic data on summer weekends is included in Appendix B.) Again, on the weekends the Scenario 4 rates are not aligned to incent greater use during afternoon hours: all three utilities set all their weekend consumption at the off-peak rate. Thus, all effects are from daily elasticities rather than substitution. Still, because of the incentive build into SCE's winter rates to conserve on weekday afternoons, the increase use during weekend afternoons is actually 50% higher than on weekdays, albeit still not significant: about 30 MW.

5.2 Scenarios 5 and 6: Aggressive Pricing

The TOU periods for Scenarios 5 thru 6 were proposed by the CAISO, and illustrative and aggressive rates were provided by the CPUC. Unlike Scenarios 1-4, Scenarios 5 and 6 include super-peak and super off-peak TOU periods, with associated exceptionally high rates at 60¢/kWh, and exceptionally low rates at 7.5¢/kWh, respectively.

The reductions observed in Scenarios 5-6 are significantly larger than the reductions seen in Scenarios 1-4. As is shown in Table 15, under Scenario 6, with aggressive pricing and 30% customer enrollment, peak reductions in demand are range from 2.0%-2.7%. When customer enrollment increases to 80% in Scenario 6, peak reductions increase significantly, up to 7.2%.

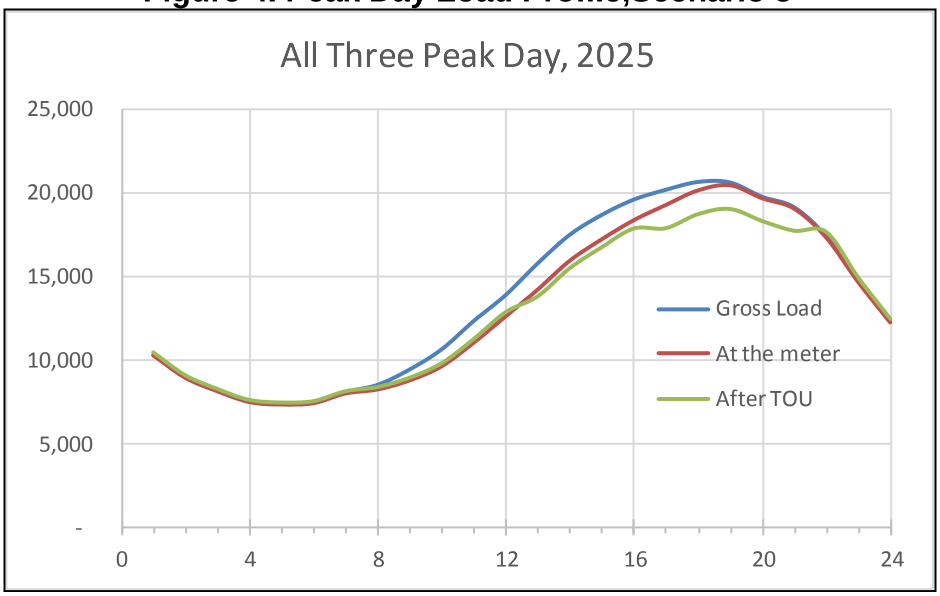
Table 12. Weekday Summer Impacts Scenarios 5-6, 2025

Scenario	Description	Change in Load (MWh)		Change in Peak (MW)	% Change in Peak
		Peak	Off Peak		
			PG&E		
Scenario 5	CAISO Proposed, Default TOU	-109,111	+75,702	-691	-7.1%
Scenario 6	CAISO Proposed, High Participation	-40,917	+28,422	-259	-2.7%
			SCE		
Scenario 5	CAISO Proposed, Default TOU	-103,659	+57,352	-656	-7.2%
Scenario 6	CAISO Proposed, High Participation	-38,872	+21,507	-246	-2.7%
			SDG&E		
Scenario 5	CAISO Proposed, Default TOU	-16,318	+5,636	-95	-5.3%
Scenario 6	CAISO Proposed, High Participation	-6,119	+2,114	-36	-2.0%

Shifts in consumption from the peak period to the off-peak period are also significantly larger under Scenarios 5 and 6. For example, under Scenario 6, there is a reduction of 40,917 MWh for PG&E. For Scenario 3, which assumes the rate of customer participation as Scenario 6, paired with PG&E's proposed TOU periods and rates, consumption is only reduced by 24,129 MWh. With greater customer participation, the impact of the rates and rate structure for the CAISO's proposed rates increases to 109,111 MWh in Scenario 5, compared with 64,343 MWh in the PG&E's proposed Scenario 4. Because the TOU structures are similar across the utilities for Scenarios 5 and 6, the phenomenon of PG&E's consumption to decrease both in the peak and off-peak periods is not observed in Scenarios 5 or 6.

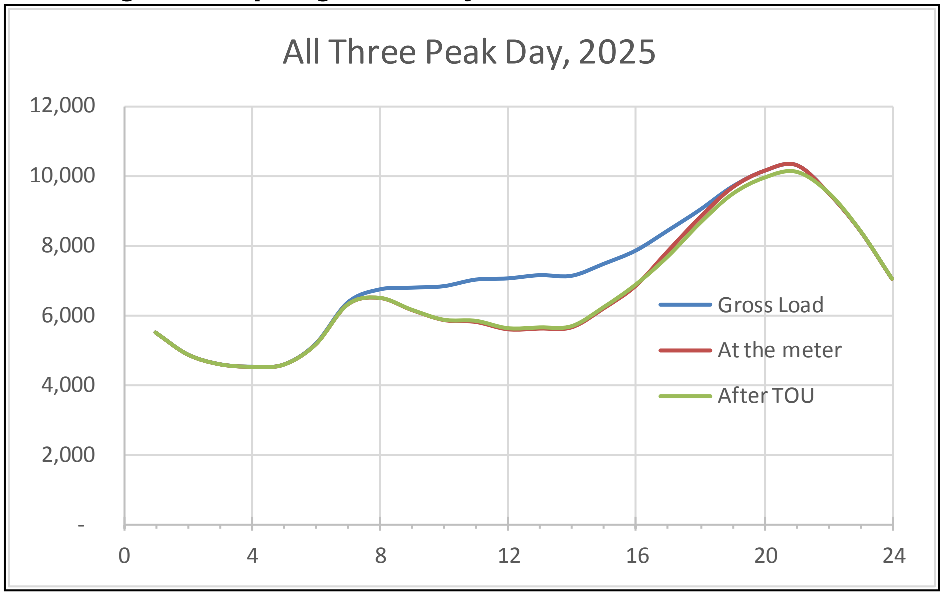
Summer peak. Figure 4 shows the residential class peak-day profile with Scenario 5 (default TOU rate). Two major differences can be seen between this figure and the analogous one for Scenario 4 (Figure 2). First, as should be expected, the magnitude of the load decrease during the peak hours is more pronounced. At the 7:00 pm peak, the TOU rates would decrease the peak demand by 1,400 MW, 125% greater than the impact with the same participation rate (80%) but the more standard TOU rate design. Second, discernible part-peak decreases can also be seen, as the green line (with TOU rates) is now distinctly below the red line (at the meter load without TOU rates).

Figure 4. Peak Day Load Profile,Scenario 5



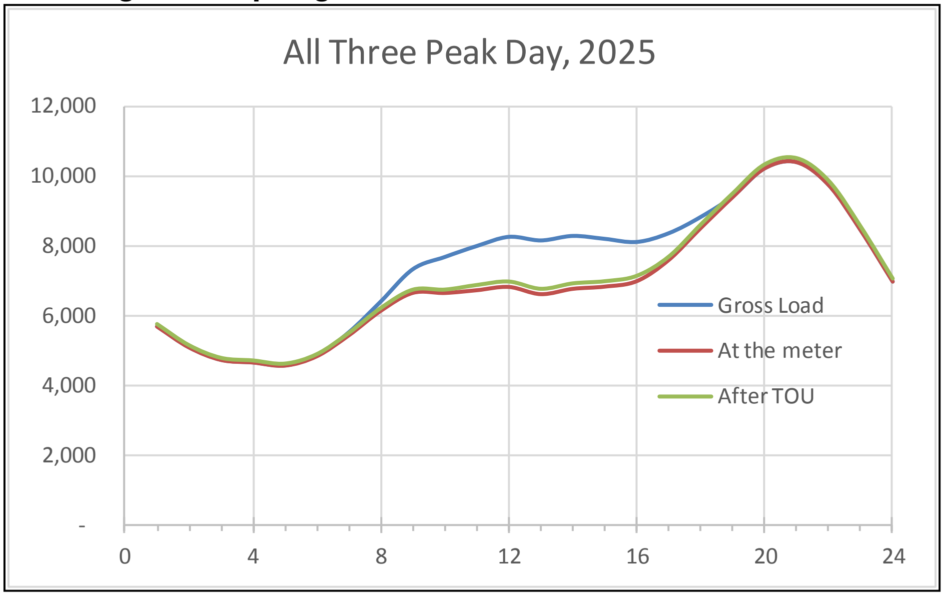
Spring Afternoon. Figure 5 shows the spring day load profile or Scenario 5, analogous to Figure 3 for Scenario 4. While now discernible on the graph, the impact of the TOU rate is still modest: an increase during the mid-afternoon of only about 60 MW. This is attributable to the small substitution elasticity of demand (-0.012). When the more aggressive (-0.066) substitution elasticity is applied, the impact more than triples to over 200 MW. While still greater than under the more standard TOU rate design in Scenario 4, it is not nearly so great as the summer peak impacts.

Figure 5. Spring Weekday Load Profile, Scenario 5



Greater impacts are observed when the more aggressive TOU rate design is applied on the spring weekends. Unlike the standard TOU rate design, the time periods remain targeted, with super-off peak rates in the mid-afternoon, with a large differential between them and the adjacent part-peak rates (ratio of 1: 2.9). In this case, greater impacts are predicted. With the base case elasticity, the load in the afternoon hours is projected to be around 150 MW, while with the very aggressive substitution elasticity the load increase modeled to be over 330 MW.

Figure 6. Spring Weekend Load Profile, Scenario 5



6. Expected+ Case Modeling Results

The Expected+ Scenario uses the same daily price elasticity inputs as the Base Case Scenario, and an estimation of substitution elasticity from the SPP, but has been modified to account for the increases in demand response observed when TOU is paired with enabling technologies. For this scenario, MRW has assumed that reductions in peak energy usage will increase by 100% when paired with enabling technology, and have implemented this in the model by doubling substitution elasticity for the Expected+ Scenario.21 Specifically, for this scenario we have assumed that 30% of customers have adopted enabling technology. Therefore, we anticipate that enabling technology will raise substitution elasticity by 100%, and with 30% customer adoption, we assume a 30% shift under the Expected+ case.

Error! Reference source not found. and **Error! Reference source not found.** below present the changes in peak consumption and demand between the Base and Expected+ cases for Scenarios 1-6. As the tables show, reductions in demand increase significantly with the adoption of enabling technologies. For example, for PG&E, the change in peak reductions under Scenario 4 increases from 234 MW to 277 MW, an increase of roughly 16%, between the Base and Expected+ cases. This impact is further increased under the more aggressive pricing scenario. Under Scenario 5, under which the greatest reductions occur, reductions in peak demand for PG&E increase from -691 MW to -847 MW between the Base and Expected+ cases, a difference of nearly 18.4%. The changes in reductions to peak period load are also significant between the cases, with PG&E achieving reductions under Scenario 5 of 109,111 MWh and -133,663 MWh, respectively.

[21] Faruqui and Sergici, Arcturus (2014) p. 70.

Table 13. Base Case and Expected+ Case Weekday Summer Impacts Scenarios 1-4, 2025

Scenario	Description	Change in Load Peak Period (MWh)		Change in Peak (MW)	
		Base	Expected+	Base	Expected+
PG&E					
Scenario 1	Current TOU, Low Participation	-13,120	-15,854	-32	-39
Scenario 2	IOU Proposed, Low Participation	-8,043	-9,540	-29	-35
Scenario 3	IOU Proposed, High Participation	-24,129	-28,620	-88	-104
Scenario 4	IOU Proposed, Default TOU	-64,343	-76,319	-234	-277
SCE					
Scenario 1	Current TOU, Low Participation	-15,900	-19,820	-48	-60
Scenario 2	IOU Proposed, Low Participation	-15,900	-19,820	-48	-60
Scenario 3	IOU Proposed, High Participation	-47,701	-59,459	-143	-179
Scenario 4	IOU Proposed, Default TOU	-127,202	-158,557	-382	-476
SDG&E					
Scenario 1	Current TOU, Low Participation	-1,919	-2,355	-4	-4
Scenario 2	IOU Proposed, Low Participation	-1,695	-2,064	-3	-4
Scenario 3	IOU Proposed, High Participation	-5,086	-6,192	-9	-11
Scenario 4	IOU Proposed, Default TOU	-13,561	-16,513	-23	-29

Table 14. Base Case and Expected+ Case Weekday Summer Impacts Scenarios 5-6, 2025

Scenario	Description	Change in Load Peak Period (MWh)		Change in Peak (MW)	
		Base	Expected+	Base	Expected+
		7. PG&E			
Scenario 5	CAISO Proposed, Default TOU	-109,111	-133,663	-691	-847
Scenario 6	CAISO Proposed, High Participation	-40,917	-50,124	-259	-318
		8. SCE			
Scenario 5	CAISO Proposed, Default TOU	-103,659	-126,472	-656	-801
Scenario 6	CAISO Proposed, High Participation	-38,872	-47,427	-246	-300
		9. SDG&E			
Scenario 5	CAISO Proposed, Default TOU	-16,318	-19,879	-95	-115
Scenario 6	CAISO Proposed, High Participation	-6,119	-7,455	-36	-43

10. Conclusions

The load impacts of residential time of use rates have been extensively investigated; there are scores of academic and conference papers analyzing nearly as many pilots. Even so, various differing variables often make direct comparisons difficult. Some are voluntary, others are opt-out; some are just for limited critical peak hours, others have set hours (which then vary between pilots). All but ones in Ontario, Canada, Pennsylvania and California did not consider impacts outside of the summer peak hours.

Using the elasticities from the California SPP and a CES-based model, MRW found that the current and proposed time of use rates can induce modest peak reductions, on the order of 100 MW to 800 MW for the three major investor owned utilities. Key factors that contribute to the range are the assumed participation rates and to a lesser degree the pentation and use of enabling technologies (i.e., devices that assist users shift their usage).

The current and IOU-proposed TOU rates have no impact on the residential loads during spring afternoons when the CAISO system is predicted to experience potential over-generation.. This is no surprise, as they weren't designed with that function in mind. In fact, SCE's rate applicable in the spring still has the full afternoon hours at a higher rate than the other hours, so as to actually induce conservation during spring afternoons.

When MRW considered hypothetical rates designed to align with the CAISO's load profile and with very aggressive TOU price differentials, the modeling suggests much greater load impacts could occur, on the order of 1,000 MW to 1,500 MW. However, the modeling still suggests that even with targeted TOU periods aggressive rate design, only modest, at best, increases in residential loads during periods where over generation is being predicted should be expected. Pilots designed to explore residential rate designs shift load into key periods are needed to better understand consumer response in these circumstances.

Because no existing pilot or study is directly applicable to the analysis here, the modeled impacts must be seen as indicative of the possible load responses rather than predictive. Additional pilots designed to specifically investigate California residential responses to particular rate designs are needed.

Appendix A

Summary Table of Relevant TOU Studies

Table 15: Summary of Relevant TOU Studies

Study	Utility	Pilot Name	Program Structure	Opt-In or Default	Minimum Monthly Consumption (kWh)	Summer On-Peak Period	Technology	Price Ratio	Own-Price Elasticity	Substitution Elasticity	Average Summer Reduction on Peak Load	Notes
Kirkeide (2012)	Salt River Project of Arizona	2008 SRP Experimental TOU Price Plan	TOU	Opt-In	1,800	3 p.m. – 6 p.m.	--	--	-0.62 to -0.66	--	25%	No net change in energy use (i.e., usage shifted but did not reduce)
						12 p.m. – 8:00 p.m.	--	--	-0.65 to -0.26	--	25%	
Faruqui and Palmer (2011)	Various	Overview of 24 pilots in North America, Europe, and Australia from 1997 to 2011	TOU	--	--	--	None	--	-0.076 to -0.12	--	0-13%	--
							Smart Thermostat	--	--	--	2-32%	
Faruqui, Sergici, and Akaba (2014)	Connecticut Light & Power Company	2009 Plan-It Wise Energy Pilot	TOU	Opt-In	--	12 p.m. – 8 p.m.	None	--	-0.453	-0.047	3.1% (High) 1.6% (Low)	An increase of 1.1% (high) and 0.6% (low) was observed in the off-peak period. The incremental effect of technology was not statistically significant.
							Smart Thermostat	--	-0.453	-0.047	3.1% (High) 1.6% (Low)	
Faruqui and	Various	Overview of 34	TOU	--	--	--	None	2:1	--	--	4.7%	--

Study	Utility	Pilot Name	Program Structure	Opt-In or Default	Minimum Monthly Consumption (kWh)	Summer On-Peak Period	Technology	Price Ratio	Own-Price Elasticity	Substitution Elasticity	Average Summer Reduction on Peak Load	Notes
Sergici (2014)		projects in seven countries						5:1	--	--	9.9%	
							Smart Thermostat	2:1	--	--	9.4%	
							Smart Thermostat	5:1	--	--	20.7%	
Potter, George, and Jimenez (2014)	Sacramento Municipal Utility District	2012-2013 Smart Pricing Options Pilot	TOU	Opt-In	--	4 p.m. – 7 p.m.	None	--	-0.166	0.131	9.4%	Off-peak elasticities for opt-in TOU was -0.053, -0.031 for default TOU, and -0.029 for TOU-CPP
			TOU	Opt-In			IHD				11.9%	
			TOU	Default			IHD		-0.069	0.038	5.8%	
			TOU-CPP	Default			IHD		-0.071	0.040	8.7%	
Williamson and Kester (2006)	Xcel Energy	2006-2007 TOU Pilot	TOU	Opt-In	1,800	2 p.m. – 8 p.m.	None	--		--	6.5%	Savings represent customers with central air conditioning (CAC). Both increase and decreases were observed in the off-peak periods.
			TOU-CPP				None		--		28.4%	
							AC Cycling Switch		--		46.8%	
									--			
							Smart Thermostat				54.4%	
Newsham and Bowker (2010)	Various	Overview of 15 North American pilots	TOU	--	--	--	--	--		--	5%	--
Jessoe, Rapson, and Smith (2012)	Undisclosed Northeastern U.S. Utility	2010 Pilot Program	TOU	Default	2,000	12 p.m. – 8 p.m.	--	--		--	5-7%	Consumption increased by 5-10% in the following months.
Hydro One	Ontario	2007 Pilot	TOU	Opt-In	--	11 a.m. –	None	--		--	3.3%	Load shifting

Study	Utility	Pilot Name	Program Structure	Opt-In or Default	Minimum Monthly Consumption (kWh)	Summer On-Peak Period	Technology	Price Ratio	Own-Price Elasticity	Substitution Elasticity	Average Summer Reduction on Peak Load	Notes
Networks Inc. (2008)	Energy Board	Program				5 p.m.	IHD				7.6%	for customers without IHD was 3.7% and 5.5% for customers with IHD.
Charles River Associates (2005)	Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric	2003-2004 California Statewide Pricing Pilot	TOU	Opt-In	--	2 p.m. – 7 p.m.	--	2.2:1	Weekday ranges from -0.050 to -0.003	Weekday ranges from -0.081 to -0.012	5.9%	2004 TOU rate impact almost completely disappeared (0.6%).
Craig (2013)	Xcel Energy	2011-2013 SmartGridCity Priging Pilot Program	TOU	Opt-In		2 p.m. – 8 p.m.	None	--		--	5-9%	--
							Saver Switch				6-8%	
				Default			None				3-6%	
							Saver Switch				5-9%	
George (2014)	PECO Energy	2013-2014 PECO Smart Time Pricing Pilot	TOU	Opt-In		2 p.m. –6 p.m.	--	--	--	--	6%	Load did not significantly increase before or after the peak periods. Load impacts in fall and winter months not statistically significant.

Summaries of TOU Studies Reviewed In-Depth

1. **Citation:** Alberini, A., and M. Filippini, "Response of residential electricity demand to price: The effect of measurement error," *Energy Economics,* 33:5 (2011), 889-895.

   Summary: This study assesses the residential demand for electricity using annual aggregate data at the state level for 48 U.S. states from 1995 to 2007. The short-run elasticities vary between -0.08 and -0.15, and the long run price elasticities between -0.45 and -0.75, depending on analysis methodology. The results of this study imply that there is room for discouraging residential electricity consumption using price increases.

   Applicability: This study is of minimal applicability, as it reviews the relationship between price and energy consumption, but does not specifically analyze the impact of time-of-use (TOU) periods on electric demand. Additionally, demand data used in this study is averaged over the continental U.S. and as such may not be directly applicable to California.

2. **Citation:** Alberini**,** A., W. Gans, and D. Velez-Lopez, "Residential consumption of gas and electricity in the US: The role of prices and income," *Energy Economics* 33:5 (2011), 870-881.

   Summary: This study presents the residential demand for electricity and gas and utilizes nationwide household-level data from 1997-2007, representative of households in the 50 largest metropolitan areas in the U.S. Using both static (fixed variables) and dynamic models (long-run vs. short-run) of electricity and gas demand, researchers conclude that there is a strong household response to energy prices, both in the short and long term. From the static models, researchers estimate the own price elasticity of electric demand in the -0.860 to -0.667 range. The price elasticity of electricity demand declines with income, but the magnitude of this effect is small. These results are in sharp contrast to much of the literature on residential energy consumption in the U.S., and suggest that there may be greater potential for policies which affect energy price than may have been previously appreciated. This study provides a table that includes historic estimations of electric price elasticities.

   Applicability: This study is of minimal applicability, as it reviews the relationship between location-specific variables, price, and energy consumption, but does not specifically analyze the impact of TOU periods on electric demand. Additionally, demand data used in this study is averaged over the major U.S. cities and as such may not be directly applicable to California.

3. **Citation:** Allcott, Hunt, "Rethinking real-time electricity pricing" *Resource and Energy Economics* 33 (2011), 820–842.

   Summary: This study evaluates residential responses to an hourly real-time pricing (RTP) program ("Energy-Smart Pricing Plan") implemented by Commonwealth Edison in Chicago, Illinois. Allcott found that enrolled households are statistically significantly price elastic (-0.1) and that consumers responded by conserving energy during peak hours, but did not increase average consumption during off-peak times.

Applicability: Even though this study examined RTP, it is interesting that the measured elasticity, -0.1, is consistent with that observed for other pricing schemes. It is also instructive to note that this study found no significant uptick in use during lower-price periods, indicating that the peak reductions were related to conservation efforts and not load-shifts.

4. **Citation:** Bell, Eric, and Stephen George, "2014 Load Impact Evaluation of Southern California Edison's Peak Time Rebate Programs," Nexant, Inc., April 1, 2015.

   Summary: This report provides the ex post and ex ante load impact estimates for SCE's Peak Time Rebate (PTR) Program, the Save Power Day (SPD) program. SPD is designed to encourage residential customers to reduce load by responding to the availability of a rebate during PTR event periods. The event period is from 2 PM to 6 PM on event days. During event hours, participating customers are eligible to receive bill credits for reductions in energy use. The study focused on three customer segments: opt-in alert PTR customers; customers with in-home displays (IHD); and customers with a programmable communicating thermostat (PCT). Opt-in PTR customers are paid $0.75/kWh for load reductions, while PCT or IHD customers are eligible to earn an additional $0.50 per kWh reduced, for a total incentive of $1.25 per kWh. There were eight event days called in 2014 between July 14 and October 3.

   For opt-in PTR customers, the average load drop was 0.08kW per participant, consistent with program year 2013 findings. The aggregate load drop from 2 PM to 6 PM was nearly 28.1 MW, representing a 4.4% reduction. The average load impact for opt-in customers varied across events, ranging from 0.05 kW to 0.10 kW. IHD customers showed a somewhat lower response, with an average event load impact of 0.04 kW and percent load impact estimate of 2%, which may be attributable to measurement error due to the much smaller population size of the participant pool and inherent variability of customer energy usage patterns. PCT study customers delivered a 26.9% load impact for the average event, resulting in a 1.6 MW aggregate reduction.

   Applicability: This study offers minimal direct applicability, as this study focused exclusively on PTR.

5. **Citation:** Borenstein, Severin, "To What Electricity Price do Consumers Respond? Residential Demand Elasticity under Increasing-Block Pricing," Working Paper, University of California, Berkeley (2009).

   Summary: This study presents the price elasticity of demand using a panel of household observations at two-year intervals, identifying elasticity from the changes in the increasing block price schedule. The primary data used in this analysis is from the residential billing records of SCE, and focuses primarily on a comparison of March through May in 2000, 2002, 2004, and 2006. The estimated impact of observed marginal price is consistently between 0 and -0.12 (medium- to long-run elasticities responding to changes in the price schedule that occurred at least a few months earlier). The estimated level of response of expected marginal price is -0.1 to -0.2, and somewhat higher for average price. The results of this study suggest that most consumers are probably responding to the expected marginal price or even less precise information about what marginal price they will face.

Applicability: This study is of minimal applicability as it does not directly explore the impact of TOU on demand. However, it is interesting that the measured elasticity, -0.12, is consistent with that observed for other pricing schemes. That this study uses California data makes the results more relevant.

6. **Citation:** Charles River Associates, "Impact Evaluation of the California Statewide Pricing Pilot," March 16, 2005.

   Summary: This study presents the results of the California Statewide Pricing Pilot (SPP), which ran from July 2003 to December 2004. This study tested several different rate structures, including traditional TOU, where price during the peak period was roughly $70 percent higher than the standard rate and about twice the value of the pricing during the off-peak period, and two varieties of critical peak pricing tariffs. The peak period for residential customers was between 2 pm and 7 pm weekday afternoons. The average peak-period price across the two summers for high price-ratio customers was $0.24/kWh and the off-peak price was $0.09/kWh, for a peak-to-off-peak price ratio of roughly 2.7:1. The price ratio for low-ratio customers was roughly 1.7:1 while the average price ratio across the two prices was 2.2:1. The average peak-period price in the winter was $0.19/kWh.

   The reduction in the peak-period energy use resulting from TOU rates in the inner summer (July through September) of 2003 equaled -5.9%. In 2003, the estimated elasticity of substitution in the inner summer equaled -0.099 and was highly significant. The elasticity of substitution for the TOU rate essentially dropped to zero in the summer of 2004. The change in daily price elasticity across the two years was much more modest than the change in the elasticity of substitution, and estimations suggest that the primary impact of the TOU rate, and the only impact in 2004, is load reduction overall, not load shifting. Overall, from 2003-2004 the daily elasticity estimates for inner summer weekday was -0.042, and -0.023 for inner summer weekend. Daily elasticity for outer summer (May, June, and October) weekday was -0.050, and -0.014 on weekends. Impacts observed in the outer winter were very small, while inner winter estimates showed a reduction of around 4% for the peak period, and an increase in energy use of around 2% for the off-peak, weekday period. Weekend energy use increases by roughly 3%. Inner winter (December, January, and February) daily elasticity estimates for weekday was -0.003, and 0.007 for weekend. In the outer winter (November, March, and April), daily elasticity estimates were -0.043 on weekdays, and 0.012 on weekends. In 2004 the TOU rate impact almost completely disappeared (0.6%). The study noted that drawing firm conclusions about the impact of TOU rates from the SPP is somewhat complicated due to the small sample size.

7. **Citation:** Faruqui, Ahmad, and Senem Sergici, "Impact Evaluation of BGE's SEP 2009 Pilot (Residential Class-Persistence Analysis)," the Brattle Group (2009).

Summary: The authors examined the persistence of energy and demand savings of participants in Baltimore Gas & Electric Company's residential Smart Energy Pricing program. The SEP program offered a PTR, with up to 12 event days per year. Overall, the study found that savings were comparable in the second year to those observed in the first year.

Applicability: This was a PTR program, and as such minimally applicable to TOU in California.

8. **Citation:** Faruqui, Ahmad, and Ryan Hledik, and Jennifer Palmer, "Time-Varying and Dynamic Rate Design" *Global Power Best Practice Series* 4 (July 23, 2012).

   Summary: This study presents results from a survey of 24 residential pricing pilots that were conducted by utilities in North America, Europe, and Australia between 1997 and 2011. Durations of the pilots lasted anywhere from a single season to four years. The study concludes that across the pilots it is apparent that time-varying rates induce peak load reductions. In general, critical peak pricing (CPP) programs supported with enabling technologies that automated customer's response resulted in the largest reductions in load. Even CPP programs without enabling technology also achieved significant reductions in load. TOU programs without enabling technologies reduce load somewhat, and have a greater impact when supported with enabling technologies. In addition to detailed case studies of international programs, the report provides a detailed summary of PG&E's 2008 SmartRate pilot program.

   Applicability: This study is generally applicable as it provides averaged summary statistics of the impact of TOU on energy consumption.

9. **Citation:** Faruqui, Ahmad, and Sanem Sergici, "Household response to dynamic pricing of electricity: a survey of 15 experiments" *Journal of Regulatory Economics* 38 (August 2010), 119-225.

   Summary: Faruqui and Sergici surveyed 15 pilots, including experiments and full-scale implementations of dynamic pricing of electricity. They found conclusive evidence that households respond to higher prices by lowering usage. The magnitude of price response depends on several factors, such as the magnitude of the price increase, the presence of central air conditioning, and the availability of enabling technologies such as two-way programmable communicating thermostats and always-on gateway systems that allow multiple end-uses to be controlled remotely. The review found a drop in peak demand of between 3% and 6% as a result of time-of-use rates, while CPP tariffs reduce peak demand between 13%-20% without enabling technologies and 27%-44% with enabling technologies.

   These included a number of California-specific studies. Of note was the California Statewide Pricing Pilot (2003-2004), which found that "TOU customers reduced their peak period usage by 5.9% during the inner summer months [July, August and September] of 2003. However, this impact completely disappeared in 2004. Due to small sample problems in the estimation of TOU impacts, normal weekday elasticities from the CPP-F treatment were found to serve as better predictors of the impact of TOU rates on energy demand than the TOU price elasticity estimates."

A study in Idaho found that the TOU rates had "no effect on shifting usage. However, in light of the very low ratio of on-peak to off-peak rates (about 1.84), this result is not so surprising. It suggests that a higher ratio of peak to off-peak rates is needed to induce customers to shift usage from peak to off-peak periods."

Applicability: The review study included both TOU and CPP pilots, including some in western states. The overall results for TOU should have some applicability in California.

10. **Citation:** Faruqui, Ahmad, and Jennifer Palmer, "Dynamic Pricing and Its Discontents," *Energy* (Fall 2011), 16-22.

    Summary: This article provides an overview of the results of several studies related to dynamic pricing in an attempt to dispel myths regarding dynamic pricing. The authors assert that customers respond to dynamic pricing rates by lowering peak usage, and cite to 24 different pilots involving a total of 109 different tests of time-varying rates where customers have reduced peak load on dynamic rates relative to flat rates with a median peak reduction of 12%. Almost 30 tests produced results in the range of 10-15%. With regard to price incentive, the authors conclude that the higher the incentive, the greater the demand response, and cited to the price elasticities of several pilot projects. Baltimore Gas and Electric's pilot, for example, revealed substitution elasticity between peak and off-peak hours of -0.096 and -0.120 in the years 2008 and 2009, respectively. Connecticut Light and Power's 2009 pilot showed substitution elasticities of -0.080 for CPP rates and -0.052 for PTR rates. Customers placed on the CPP rate in the California Statewide Pricing Pilot exhibited a substitution elasticity of -0.076, and Michigan customers in a Consumers Energy pilot showed -0.107 as their substitution elasticity. In each case, for a given elasticity of substitution, the demand response tended to increase with a higher peak to off-peak ratio, but at a decreasing rate. Impacts increase for customers with enabling technologies. For example, across all 39 pilots with enabling technologies the median peak reduction is 23%, 9% higher than the median across all 109 tests. The authors also argue that customer response to demand response will last for multiple years, and cite to California's Statewide Pricing Pilot, conducted from July 2003 through December 2004 by PG&E, SCE, and SDG&E. The pilot ran across two summers and was able to show that energy use reduction of fixed CPP over the two summers was not statistically significant.

    Applicability: This study has minimal direct applicability, as it focused exclusively on CPP and PTR tariffs, which is not applicable to TOU elasticities.

11. **Citation:** Faruqui, Ahmad, and Jenny Palmer, "The Discovery of Price Responsiveness – A Survey of Experiments involving Dynamic Pricing of Electricity," *EDI Quarterly* 4:1, 15-18.

Summary: This paper surveys the results of 129 pricing experiments with dynamic and TOU pricing, from a total of 24 pricing studies. The experiments have been carried out across three continents at various times during the past decade. Across the pricing tests, peak reductions range from 0-60%. This study focuses on nine of the best-designed and most recent experiments to examine the impact of the peak to off peak price ratio on the magnitude of the reduction in peak demand, or demand response. Data from 74 of these experiments is sufficiently complete to determine the relationship between peak to off-peak price ratio, and the associated reduction in peak demand or demand response. The result is an "arc of price responsiveness" which shows that the amount of demand response rises with the price ratio but at a decreasing rate. About half of the variations in demand response can be explained by the variations in price ratio. Enabling technologies such as IHDs, energy orbs, and programmable and communicating thermostats boost the amount of demand response. Overall, the results of this paper support the case for widespread rollout of dynamic and TOU pricing.

Applicability: This study reviewed both TOU and CPP pilots, including some in California. The overall results for TOU should have applicability in California.

12. **Citation:** Faruqui, Ahmad, and Ryan Hledik, "Transition to Dynamic Pricing," *Fortnightly Magazine* (March 2009).

    Summary: This article presents general TOU rate design principals and strategies.

    Applicability: While not applicable to TOU rate impact, these principals and strategies may be helpful in guiding rate design strategies for modeling.

13. **Citation:** Faruqui, Ahmad, Sanem Sergici, and Lamine Akaba, "Dynamic Pricing of electricity for residential customers: the evidence from Michigan" *Energy Efficiency* 6 (2013), 571-584.

    Summary: This study analyzes data from a pilot project in Michigan which featured two dynamic pricing rates and an enabling technology. This pilot also included a group of "information only" customers who were provided information on time-varying prices but billed on standard rates. The pilot ran from July 2010 through September 2010, and observed various treatments, of which two involved dynamic pricing rates—CPP and PTR, both of which were layered atop a TOU rate. There were six critical even days during the course of the pilot period, with peak hours between 2 to 6 PM. Customers enrolled in the pilot received lower off-peak rates. The CPP customers received technology options; PTR customers were not tested with technology. Researchers concluded that customers, including low-income participants, do respond to dynamic pricing, and that the response to CPP rates is similar to the response to peak time rebates. This last finding is both consistent and inconsistent with results of previous studies. Specifically, the price elasticity for CPP customers with technology was -0.089, which is twice as high as the value observed in a 2008 Maryland pilot. Substitution elasticities for CPP and PTR customers with and without technology were -0.107. CPP customers with technology reduced their consumption by

19.4%, and CPP and PTR customers without technology reduced consumption by 15.2% and 15.9%, respectively.

Applicability: This study affords only limited applicability, as it focused exclusively on CPP and PTR tariffs.

14. **Citation:** Faruqui, Ahmad, and Sanem Sergici, "Arcturus: An International Repository of Evidence on Dynamic Pricing" in *Smart Grid Applications and Developments*, ed. Daphne Mah, Peter Hills, Victor O.K. Li, and Richard Balme, (London: Springer London, 2014), 59-74.

    Summary: This study introduces Arcturus, an international database of dynamic and TOU pricing studies. It contains the demand response impacts of 163 pricing treatments that were offered on an experimental or full-scale basis in 34 projects in seven countries located in four continents. Treatments included various types of dynamic pricing rates and simple TOU rates, some of which were offered with enabling technologies such as smart thermostats. Response impacts varied widely, from 0 to 50%, which have led some observers to conclude that it is unclear whether or not customers respond to dynamic pricing. This study finds that much of the discrepancy in the results goes away when demand response is expressed as a function of the peak-to-off-peak price ratio. In this form, customers respond to rising prices by lowering their peak demand in a fairly consistent fashion across the studies. The response curve is shaped like an arc, as price incentive to reduce peak use is raised, customers respond by lowering peak use, but at a decreasing rate. The use of enabling technology boosts the amount of demand response. Overall, there is a significant amount of consistency in the experimental results, especially when the results are disaggregated into TOU rate and dynamic pricing rates. Specifically, when using a regression model (MM estimator) which limits the influence of outliers to quantify the effect of the price ratio and use of enabling technology on demand response, the expected peak reduction in TOU only and TOU with technology experimental treatments for a price ratio of 2:1 was 4.7% and 9.4%, respectively. For a price ratio of 5:1, expected peak period reductions were 9.9% and 20.7%, respectively.

    Applicability: Because this study presents an aggregate result of the TOU impact, its result are generally to the California TOU modeling effort, with the one caveat that the locations where data was collected are not explicitly stated.

15. **Citation:** Faruqui, Ahmad, Sanem Sergici, and Lamine Akaba, "The Impact of Dynamic Pricing on Residential and Small Commercial and Industrial Usage: New Experimental Evidence from Connecticut," *The Energy Journal* 35:1 (2014), 137-160.

    Summary: This study presents results of a June to September 2009 pilot in Connecticut which featured CPP, PTR, and TOU rates, with and without four enabling technologies. Under the CPP and PTR rate design, there were ten critical peak days, with the peak period running from 2 to 6 PM. Peak hours for TOU were from 12 to 8 PM. Daily elasticity estimates for TOU with and without technology was -0.453, and -0.026 for CPP and PTR with and without technology. Substitution elasticities for TOU with and without technology was -0.047, -0.081 for CPP without technology and -0.128 with technology, and -0.052 for PTR without technology and -0.1 with technology. The high estimate of the consumption impact for CPP customers during peak hours of event days without technology is a reduction of 16.1%, and 23.3% with technology. Slight increases were observed in off-peak hours for event days, and in peak and off-peak hours of non-event days. The high estimate of the consumption impact for PTR customers during peak hours of event days without technology was a reduction of 10.9%, and 17.8% with technology. A slight decrease was observed in off-peak hours for event days, and no change was seen in peak and off-peak hours for non-event days. The high estimate of the consumption impact of TOU was a 3% reduction in consumption, and a 1.1% increase in off-peak consumption. Overall researchers concluded that 1) customers respond to dynamic pricing; 2) response to crucial peak pricing rates is higher than response to peak time rebates; 3) there is virtually no response to TOU rates with an eight hour peak period; and 4) small commercial and industrial customers are less price responsive than residential customers.

Applicability: This report is generally applicable as it includes TOU results, however seasonal differences between California and Connecticut may limit the study's applicability.

16. **Citation:** Fell, Harrison, Shanjun Li, and Anthony Paul, "A New Look at Residential Electricity Demand Using Household Expenditure Data," Colorado School of Mines, *Division of Economic and Business Working Paper Series* 4 (July 2012).

    Summary: This study presents estimated residential electricity demand under the assumption that consumers respond to average prices rather than to marginal prices. The primary source of data for the demand estimation is from the consumer expenditure survey (CEX) from the Bureau of Labor Statistics, monthly from 2006 to 2008, supplemented with state- and utility- level data from the Energy Information Administration. Results consistently show a price elasticity of electricity demand near -1 across many different specifications. This estimate is at the upper end (in magnitude) among the large set of price elasticity estimates in the literature, which range from zero to less than -1. However, the other studies assume that households respond to marginal electricity prices rather than average electricity prices.

    Applicability: This study is of moderate applicability, as it reviews the relationship between price and energy consumption, but does not specifically analyze the impact of TOU periods on electric demand. Additionally, data used in this study is averaged over U.S. households and as such may limit its applicable to California.

17. **Citation:** George, Stephen, Aimee Savage, and Dan Thompson, "2014 Load Impact Evaluation of Pacific Gas and Electric Company's Residential Time-based Pricing Programs," Nexant Inc., April 1, 2015.

    Summary: This report presents the ex post and ex ante load impact estimates for PG&E's residential time-based pricing tariffs for the 2014 program year (from November 1, 2013 to October 31, 2014). PG&E has three time-based tariffs in effect, and only are two are open to new enrollment. The tariffs are 1) SmartRate, a program available to other tariffs including non-TOU, has a high price during the peak period on event days, and slightly lower prices at all other times during the summer (12 SmartDays were called in 2014); 2) rate E-7 is a two-period static TOU rate with a peak period from 12 to 6 PM (now closed to enrollment); and 3) rate E-6 is a three period TOU rate with a peak period from 1 to 7 PM in the summer and from 4 to 8 PM in the winter. Customers enrolled in PG&E's SmartRate and SmartAC programs are considered "dually enrolled" participants.

The average load impact across the 12 SmartDays in 2014 equaled 0.21 kW for SmartRate-only participants, and 0.51 kW for dually enrolled participants. Aggregate load reduction for the average event was 18.3 MW and 20.4 MW for SmartRate only customers and dually enrolled customers, respectively, which produced a total average aggregate impact of 39 MW. Average impacts for SmartRate only customers was a reduction of 14%, and 25% for dual customers, approximately 20% less than the 2013 average despite comparable weather conditions across the two years. For E-6 customers load reductions were greater over the summer than the winter, when the difference between peak and off-peak prices is the largest and the peak period goes from 1 to 7 PM. During the summer, the average load reduction for E-6 customers was 0.22 kW, or 20%, and the aggregate load reduction was 1.9 MW. During the winter, the average load reduction was 0.11 kW, or approximately 8%, and the aggregate load reduction was 0.9 MW. This is substantially less than the aggregate impacts for the SmartRate tariff and also less than for the E-7 tariff. The average summer impact for E-7, which has a peak period from 12 to 6 PM, was approximately 0.15 kW, or 9%, and the aggregate impact was roughly 7.4 MW. During the winter, the average load reduction was 0.05 kW, or 5%, and the aggregate load impact was 2.65 MW.

Applicability: This generally applicable as it included review of TOU tariffs in California.

18. **Citation:** George, Stephen, Candice Churchwell, and Jeeheh Oh, "San Diego Gas and Electric Company Summer Saver 2014 Program Evaluation," Nexant Inc., April 2015.

    Summary: This report presents ex post load impact estimates for the 2014 Summer Saver program and ex ante load impact forecasts for 2015-2025. The Summer Saver program is available to residential and nonresidential customers and runs from May 1 through October 31. An event may be triggered by temperature or system load conditions, and customers are not automatically notified when an event occurs, however they may sign up to receive notification. Residential customers can choose between 50% or 100% cycling. The incentive option varies. Eight Summer Saver events were called in 2014 and each lasted four hours. Three of the six events were from 2 to 6 PM, with the others going from 12 to 4 PM, 3 to 7 PM, and 4 to 8 PM. For the events from 2 to 6 PM, aggregate demand reduction for residential customers equaled 11.2 MW. The average per household load reduction equaled 0.42 kW.

    Applicability: This study is only somewhat applicable to the California TOU modeling effort because the pilot focused on a non-TOU dynamic pricing tariff. Observed trends in customer behavior may be applicable as the pilot took place in California.

19. **Citation:** George, Stephen, Michael Sullivan, Josh Schellenberg, and Alana Lemarchand,

"Dynamic Pricing PECO Smart Time Pricing Pilot Final Report," Nexant Inc., April 27, 2015.

Summary: This report presents the results of PECO Energy's Smart Time Pricing residential and small commercial pilot program which ran from November 2013 to December 2014. The program combined a TOU rate with a bill protection feature plus a no-fee cancelation provision. The TOU rate structure offered a reduced rate for electricity usage for most hours of the year and a higher rate during non-holiday, weekday afternoons from 2 PM – 6 PM. The program had a peak generation rate of $0.1595 per kWh on weekdays, excluding holidays, and an off-peak generation rate of $0.0685 per kWh during the remaining hours of the year. The TOU rate remained the same or the duration of the pilot program. PECO's default generation rate was $0.0935 per kWh at the time solicitations began. In July 2014, the month with the highest average usage of all 14 months analyzed for the study, the average peak reduction of whole-house load was 5.7%, resulting in an aggregate peak load reduction of 459 kW. Load did not significantly increase before or after the peak period in the month of July, suggesting that peak loads were largely reduced as opposed to shifted to off-peak hours. This was also the case in other summer months, including June, August, and September 2014.

On average, TOU pricing participants had peak loads that were about 6% lower than those of the control group during the summer peak hours (June through August 2015), resulting in an average load impact of 0.09 kW to 0.11 kW, and an aggregate load reduction of 367 kW to 459 kW. During September and spring months (March through May), load reductions were about 3% to 4%. Aggregate impacts fluctuated throughout these periods due to rising and falling program enrollment. In the fall and winter months, load impacts were largely not statistically significant, due to lower enrollment and usage.

20. **Citation:** Hydro One Networks Inc., "Time-of-Use Pricing Pilot Project Results," May 2008.

    Summary: This study presents the results from a May- September 2007 TOU pilot study in Ontario, Canada (on-peak from 11 AM to 5 PM). For a typical customer on the TOU rates, the load-shifting impact averaged 3.7% in the summer months and consumption decreased 3.3%. For TOU customers with IHDs, the load-shifting impact increased to 5.5%, and consumption declined 7.6%. On a hot summer day, the load-shifting impact was even more pronounced at 8.5% (when applied to all residential customers this would be equivalent to 150 MW). Of the pilot participants under TOU, 76% paid a lower electricity bill as a result of load-shifting, and 72% indicated that they would like to remain on the TOU rates.

    Applicability: This report is generally applicable as it included TOU results, however seasonal differences between California and Ontario may call into doubt the study's applicability.

21. **Citation:** Ito, Koichiro, "Do consumers Respond to Marginal or Average Price? Evidence from Nonlinear Electricity Pricing" *American Economic Review* 104:2 (February 9, 2015), 537-563.

Summary: This study analyzes household level billing history of all SCE and SDG&E residential customers in the territory border between SCE and SDG&E in Orange County from 1999 to 2007. Ito finds strong evidence that consumers respond to the average price of their electricity bills, rather than marginal or expected marginal price. Average price has a significant effect on consumption, while the effects of marginal price and expected marginal price become statistically insignificant. Ito argues that if customers respond to average price rather than marginal cost, than a fixed credit on electricity bills actually discourages conservation and increases electricity consumption.

Applicability: This study is not directly applicable because the pilot focused on a non-TOU dynamic pricing tariff. Some observed trends in customer behavior may be applicable as the pilot took place in California.

22. **Citation:** Ito, Koichiro, Takanori Ida, and Makoto Tanaka, "The Persistence of Moral Suasion and Economic Incentives: Field Experimental Evidence from Energy Demand" *E2e Working Paper 017* (February 9, 2015).

    Summary: This study presents the results of an experiment that monitored the electric consumption of households in Japan during the summer of 2012 and winter of 2013 (on-peak period of 1 p.m. to 4 p.m. in summer, 6 p.m. to 9 p.m. in winter), in response to both moral and economic signals. During peak demand hours on peak demand days, the moral group was asked to exercise voluntary energy conservation with no economic incentives, while the economic group was charged high electricity prices during peak demand hours. The implied price elasticity estimates are -0.136 for the summer and -0.141 for the winter.

    This study found that the moral suasion group showed a usage reduction of 8% for the first few treatment days. However, their usage became statistically indistinguishable from that of the control group for the remaining interventions. The economic incentives created much larger and persistent effects. The economic incentive group showed usage reductions of 14% for the lowest critical peak price. This effect was persistent over repeated interventions. Unlike the moral group, the economic incentive group showed additional usage reductions during non-treatment hours.

    Applicability: This study is only somewhat applicable, as it focuses on CPP rather than TOU tariffs. Additionally, social differences between California and Japan would also call into doubt the study's applicability.

23. **Citation:** Jessoe, Katrina, and David Rapson, and Jeremy Blair Smith, "The Effect of a Mandatory Time-of-Use Pricing Reform on Residential Electricity Use," November 27, 2012.

    Summary: This paper analyzes short-run household responses to a large-scale field deployment of TOU pricing. Data used in this study is from the first large-scale residential field deployment, implemented by a northeastern utility. Households with consumption that exceeded a specific threshold (4,000 kWh per month in 2006; 3,000 kWh in 2008; and 2,000 kWh in 2009) were forced to switch from a flat-rate plan to one with a high electricity price during peak hours (noon through 8 PM on weekdays) and a low price during all other hours. Researchers concluded that after being switched to TOU, large households substantially reduced their total electricity consumption during the summer months. Households above the 4,000 kWh monthly threshold reduced total electricity expenditure in the summer months of 2008 by more than 20% each month, and as much as 30% in July. Overall consumption decreased by 9-10% in the months of June and July. The switch to TOU caused substantial declines in on-peak usage in June and July 2008, by about 13%. TOU also caused significant though proportionally smaller declines in off-peak usage in the same months. Three is weak evidence of a decrease in on-peak usage in February 2008. With the lower 2,000 kWh monthly threshold, TOU resulted in customers reducing total consumption by 5% in July 2010, with increase in total usage of 5-10% in each of the following months. There is suggestive evidence that TOU caused drops in total bills of about 5-7% in the spring months of 2010. TOU's effects on peak and off-peak usage are limited to the summer months. The drop in total usage in July 2010 caused by TOU appears to be more heavily weighted towards a decline in off-peak usage. With regard to load shifting, there is very weak evidence of a moderate degree of load shifting across the three experiments, but elasticity estimates are provided that are statistically insignificant at conventional levels.

Applicability: This study is marginally applicable as it TOU impact data on both on-peak and off-peak. Differences in climate between California and the northeastern U.S. may limit the study's applicability.

24. **Citation:** Jessoe, Katrina and David Rapson, "Knowledge is (Less) Power: Experimental Evidence from Residential Energy Use," *American Economic Review* 104:4 (2014), 1417-1438.

    Summary: The authors examined the effect of "high frequency information" on customer's electricity usages during CPP events. They investigated whether the low electric price elasticity of demand shown in the literature is attributable to genuine inelastic demand or because the lack of complete information. The accomplished this be providing selected United Illuminating (Connecticut) CPP customers real-time feedback on the quantity of electricity being consumed via an IHD and comparing the behavior of those customers to customers on the CPP rate without the IHD. Households in the price-only group reduced their usage by 0-7% during pricing events (depending on the amount of advance notification they received), relative to control. In contrast, those exposed to the same price changes but who also have IHDs, exhibit much larger usage reductions of 8-22%.

    Applicability: No direct applicability as this study focused exclusively on CPP. It does, however, highlight the impact and importance of IHDs.

25. **Citation:** Kirkeide, Loren, "Effects of Three-Hour On-Peak Time-of-Use Plan on Residential Demand during Hot Phoenix Summers" *The Electricity Journal* 25:4 (May 2012): 48-62.

Summary: Kirkeide presents the results of A Salt River Project (SRP) pilot program in which the utility offered a voluntary TOU rate (EZ-3) with a 3-hour peak pricing period (3:00 p.m. to 6:00 p.m.). SRP's existing residential TOU rate (E-26) encompassed peak rates from noon to 8:00 p.m. from May through October. Prior analysis of this E-26 TOU rate in (1988) found an aggregate decrease in summer peak demand corresponding to a price elasticity of demand of -0.28. In the 1988 study, there were two TOU plans, with a 3:1 ad 5:1 peak to off-peak price ratio. The customers on the 3:1 price differential reduced summer peak demand by an average of 8.8% while the customers on the 5:1 price differential reduced summer peak demand by an average of 11.0%.

The study documented here found that going from a non-TOU rate (E-23) to the EZ-3 rate had an implied price elasticity of -0.62 to -0.66 going from the existing TOU rate (E-26, 12:00-8:00) to the EZ-3 rate had an implied price elasticity of -0.65 to -0.26. Both cases resulted in a 25% decrease in coincident peak demand when the customer moved to EZ-3, but no net change in energy use (i.e., usage shifted but did not reduce).

Applicability: Sumer peak loads in the SRP territory are driven by air conditioning load. As such, the results may applicable only to inland areas with high air conditioner penetration. Furthermore, the SRP program was targeted towards higher users, so again the results may not hold in all California climate zones.

26. **Citation:** Krishnamurthy, Chandra, and Bengt Kristrom, "Energy demand and income elasticity: a cross-country analysis," Working Paper, Center for Environmental and Resource Economics (August 2013).

    Summary: This study provides cross-country estimates of price and income elasticity for 11 Organization for Economic Co-operation and Development (OECD), using data from a survey conducted by the OECD in 2011. Using data for annual consumption of electricity and sample-derived average electricity price, this study provides estimates of country-specific and average income elasticity. For most countries, strong price responsiveness is found with elasticities varying from -0.27 to -1.4, with most countries' elasticity being above -0.5. This study also finds evidence for non-price related factors to significantly effect energy demand, particularly households' self-reported energy saving behavior appears to reduce energy demand between 2 to 4%.

    Applicability: This study is of minimal applicability, as it reviews the relationship between price and energy consumption, but does not specifically analyze the impact of TOU periods on electric demand. Additionally, demand data used in this study is averaged and may not be directly applicable to California.

27. **Citation:** Lawson, Rob, Paul Thorsnes and John Williams, "Consumer Response to Time Varying Prices for Electricity" *University of Otago Economics Discussion Papers* 1116 (November 2011).

    Summary: The study reported experimental evidence of the household response to weekday differentials in peak and off-peak electricity prices. The data comes from Auckland, New

Zealand, where peak residential electricity consumption occurs in winter for heating. Peak/off-peak price differentials ranged over four randomly-selected groups from 1.0 to 3.5. On average, there was no response except in winter. In winter, participant households reduced electricity consumption by at least 10%, took advantage of lower off-peak prices but did not respond to the peak price differentials. Response varied with house and household size, time spent away from home, and whether water was heated with electricity.

Applicability: This study is of very minimal applicability, as it was over a short period (less than a year) and for a winter-peaking utility whose peak is driven by electric heating. Social differences between California and New Zealand would also call into doubt the study's applicability.

28. **Citation:** Newsham, Guy, and Brent Bowker, "The effect of utility time-varying pricing and load control strategies on residential summer peak electricity use: A review," *Energy Policy* 38 (2010), 3289-3296.

    Summary: This study reviews several North American dynamic pricing studies. Researchers conclude that the most effective strategy to curtail loads during high demand periods is a CPP program with enabling technology to automatically curtail loads on event days. A peak load reduction of at least 30% can be expected with such technology. A simple TOU program can only expect to realize on-peak reductions of 5%, likely to be maintained over several years. The authors note, however, that this is not insignificant. A 2004 study estimated that a reduction of only 2-5% in system-wide demand at peak times could reduce the spot price for electricity by 50% or more, and a 2009 study estimated that a 5% reduction in US demand during the highest 1% of demand hours would save $3 billion per year. Within the CPP and TOU studies, there is no clear trend for an effect of on-peak/off-peak price ratio on peak load reduction.

    Applicability: This review study included both TOU and CPP pilots, including some in California. The overall results for TOU should have some applicability in California.

29. **Citation:** Potter, Jennifer, Stephen George, and Lupe Jimenez, "SmartPricing Options Final Evaluation," Prepared for SMUD, September 5, 2014.

    Summary: This report presents the load impacts of the SMUD's SmartPricing Options (SPO) pilot, a program supported by the Department of Energy's Smart Grid Investment Grant. SPO is a multi-year pricing pilot that tested three time-variant pricing plans (TOU with 4-7 PM peak, CPP, and a combination of the two), and two different recruitment strategies (opt-in and default). The SPO also tested the impact of the offer of an in-home display on customer enrollment for opt-in recruitment. For the study, time-variant rates were effective from June 1 through September 30 for the summers of 2012 and 2013. Critical peak prices were in effect for 23 days. On average, the TOU rate impact ranged from 0.11 to 0.21 kWh, or 5.8% to 11.9%, depending on the type of recruitment type and IHD offer. On average the CPP rate impact ranged from 2.24 to 2.56 kWh, or 5.9% to 20.9%, depending on recruitment type, TOU enrollment, and IHD offer. Own-price elasticities for non-economics assistance program (EAPR) TOU customers for peak consumption ranged from -0.166 to -0.069, depending on enrollment type. Elasticities for CPP non-EAPR CPP customers for peak consumption ranged from -0.159 to -0.064, depending on enrollment type, and -0.071 for TOU-CPP customers. In general, opt-in customers had greater load reductions. The study also provided estimations of cross-price elasticity of peak consumption with respect to off-peak price, cross-price elasticity of off-peak consumption with respect to peak price, and price elasticity of the off-peak period.

Applicability: This study is generally applicable as it provides an assessment of TOU impact on California residents. This study is most applicable to inland areas.

30. **Citation:** Rowlands, Ian, and Ian Furst, "The cost impacts of a mandatory move to time-of-use pricing on residential customers: an Ontario (Canada) case-study," *Energy Efficiency* 4 (2011), 571-585.

    Summary: This paper presents results of a cost impact study in which customers in Ontario on a two-tier electric rate system were placed on time-of-use pricing at different times between October 2005 and April 2008. Researchers concluded that customers that have a relatively high level of consumption in either peak periods or wintertime are more likely to have higher bills under a time-of-use regime. Households that consume higher quantities of electricity are more likely to have lower bills under a time-of-use regime, as compared to a two-tier regime. Overall 45% of customers have lower bills under a TOU regime, while 55% of customers have higher bills. Percentage changes in monthly electricity bills were, for the most part, relatively small. For 98.2% of the sample, the bill change was within 5%. Of the remaining 1.8%, some households saw increases above 5%, and some saw decreases greater than 5%. The average relative change is an increase of 0.233%.

    Applicability: This report is generally applicable as it includes TOU results, however seasonal differences between California and Ontario may limit the study's applicability.

31. **Citation**: Williamson, Craig, and Bridget Kester, "Xcel Energy TOU Pilot Final Impact Report," Energy Insights Consulting, 2006.

    Summary: This study presents the results from Xcel Energy's TOU pilot program to assess customer response to time-based rates and associated enabling technologies. Residential customers in the Denver area with at least 1,800 kWh billing consumption for the summer were assigned either a TOU rate, CPP rate, or both based on tier preference. The pilot ran from July 2006 to July 2007 with 10 event days. High temperatures on event days ranged from 93 to 100, and lows from 60 to 71. Over the course of the entire summer period, the pilot customers in all groups reduced energy use in both critical peak and on-peak periods. Critical peak reductions for CPP and CPP/TOU customers with and without technology and with and without central air conditioning (CAC) ranged from 15.45% to 54.35%. On peak reductions for CPP and CPP TOU customers with and without technology ranged from 2.47% to 10.24%. Load impacts in the off peak for CPP/TOU customers with and without technology and with and without CAC ranged from increases 5.52% to a decrease of 1.20%. On peak reductions for TOU customers without technology and air conditioning was approximately 10.67%. TOU customers without technology and with CAC reduced load by 5.18%. TOU customers with no technology and no CAC reduced load in the off-peak by

3.72%, while customers with CAC increased consumption by 3.54%. This study provides other load impact estimations that may or may not be equivalent to an estimation of elasticity of demand. In general, customers with CAC reduce their peak load more than customers without central AC.

Applicability: This report is generally applicable as it includes TOU results, however seasonal differences between California and Colorado may limit the study's applicability.

32. **Citation:** Williamson, Craig, "SmartGridCity™ Pricing Pilot Program Impact Evaluation Results, 2011-2013," EnerNoc Utility Solutions Consulting, 2013.

    Summary: The report presents the results of a 3-year rate pilot for Xecel Energy designed to determine the impact time differentiated pricing structures have on customer behavior. The study included approximately 4,000 customers participating in this pilot. The participants were taken from Boulder. Colorado SmartGridCity (smart meter) accounts and represented about 20% of the accounts. The study looked at CPP rates, a PTR program, and TOU rates. The pilot contained both opt-in and opt-out phases.

    The pilot confirmed that these rates positively impact customer behavior resulting in energy savings with each of the three pilot rates. Most notably, CPP rate provided greater load reductions than both PTR and TOU rates. Customers on the CPP rate realized reduced peak demand approaching 30%, PTR participants realized load reductions of nearly 15% and TOU participants averaged 5-9%. Given the pricing structure, this implies an elasticity of demand of -0.06 to -0.10.

    The study also found a drop-off in savings over time, as well as increased savings from the opt-in cohort relative to the opt-out group. It also found that its simple air-conditioning control program ("Saver's Switch") was more effective in reducing demand than any of the rate-based options. The study also found the greatest impact from homes with air conditioning.

    Applicability: The report is generally applicable to California, it stated that the results from the Boulder pilot were consistent with those of other TOU/CPP programs, and provided detail with respect to different types of customers.

33. **Citation:** Wolak, Frank, "Do Residential Customers Respond to Hourly Prices? Evidence for a Dynamic Pricing Experiment" *American Economic Review: Papers & Proceedings* 101:3 (May 2011), 83-87.

    Summary: Wolak uses the results of a dynamic pricing experiment to compare the magnitude of the demand reduction obtained from hourly pricing to the demand reduction obtained from an alternative dynamic pricing tariff that pre-commits to a longer duration of high prices to determine whether this "cost of taking action" exists. Based on data from the Power Cents DC program in Washington, D.C., Wolak found that the magnitude of the average hourly percentage demand reduction from hourly pricing is roughly equal to the estimated percentage demand reduction over a longer duration of high prices, once the demand reduction under hourly pricing is adjusted for the ratio of the percentage price increases under the two dynamic pricing programs. This result argues against the existence of a “cost of taking action” associated with charging customers retail prices that vary with hourly system conditions.

Applicability: This study affords minimal direct applicability, as the study focused exclusively on dynamic pricing tariffs (e.g., CPP).

Appendix B: Detailed Results Tables